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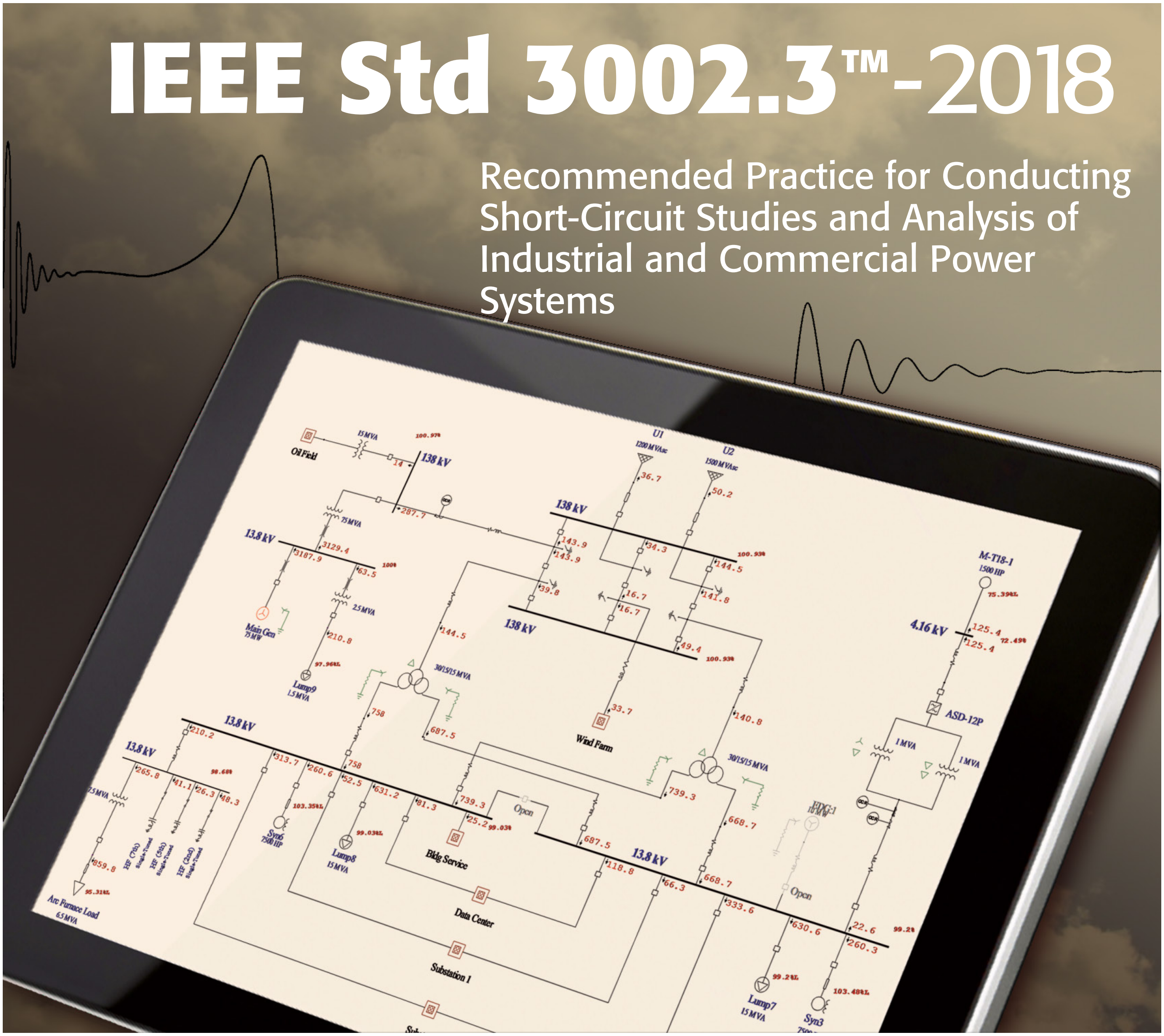
**IEEE 3002 STANDARDS:**
POWER SYSTEMS ANALYSIS

# IEEE Std 3002.3™-2018

## Recommended Practice for Conducting Short-Circuit Studies and Analysis of Industrial and Commercial Power Systems

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# IEEE Recommended Practice for Conducting Short-Circuit Studies and Analysis of Industrial and Commercial Power Systems

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**IEEE-SA Standards Board**

**Abstract:** Activities related to short-circuit analysis, including design considerations for new systems, analytical studies for existing systems, as well as operational and model validation considerations for industrial and commercial power systems are addressed. Fault current calculation and device duty evaluation is included in short-circuit analysis. Accuracy of calculation results primarily relies on system modeling assumptions and methods used. The use of computer-aided analysis software with a list of desirable capabilities recommended to conduct a modern short-circuit study is emphasized. Examples of system data requirements and result analysis techniques are presented.

**Keywords:** ac decrement, asymmetrical fault current, available fault current, bolted fault, breaking capacity, breaking duty, data collection, dc component, dc decrement, dc offset, device duty calculation, fault calculation, fault duty, IEEE 3002.3, interrupting capacity, interrupting duty, making capacity, making duty, momentary capacity, momentary duty, short-circuit analysis, short-circuit current, short-circuit studies, short-circuit withstand, symmetrical component, symmetrical fault current, system modeling, system validation, *X/R* ratio

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# Introduction

This introduction is not part of IEEE Std 3002.3-2018, IEEE Recommended Practice for Conducting Short-Circuit Studies and Analysis of Industrial and Commercial Power Systems.

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This recommended practice was developed by the Technical Books Coordinating Committee of the Industrial and Commercial Power Systems Department of the Industry Applications Society, as part of a project to repackage the popular IEEE Color Books®. The goal of this project is to speed up the revision process, eliminate duplicate material, and facilitate use of modern publishing and distribution technologies.

When this project is completed, the technical material included in the 13 IEEE Color Books will be included in a series of new standards—the most significant of which will be a new standard, IEEE Std 3000™, IEEE Recommended Practice for the Engineering of Industrial and Commercial Power Systems. The new standard will cover the fundamentals of planning, design, analysis, construction, installation, startup, operation, and maintenance of electrical systems in industrial and commercial facilities. Approximately 60 additional dot standards, organized into the following categories, will provide in-depth treatment of many of the topics introduced by IEEE Std 3000™:

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## IEEE Std 3002.3™

The material in this recommended practice partially comes from IEEE Std 551™, IEEE Recommended Practice for Calculating AC Short-Circuit Currents in Industrial and Power Systems (*IEEE Violet Book*™) and IEEE Std 399™, IEEE Recommended Practice for Industrial and Commercial Power System Analysis.[1, 2]

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# Contents

# IEEE Recommended Practice for Conducting Short-Circuit Studies and Analysis of Industrial and Commercial Power Systems

## 1. Scope

This recommended practice describes how to conduct short-circuit studies and analysis of industrial and commercial power systems. It is likely to be of greatest value to the power-oriented engineer with limited experience in this area.

## 2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

ANSI/IEEE Std C37.5™, IEEE Guide for Calculation of Fault Currents for Application of AC High-Voltage Circuit Breakers Rated on a Total Current Basis.[1]

IEC 60909, Short-circuit currents in three-phase a.c. systems.[2]

IEC 61363-1:1998, Electrical installations of ships and mobile and fixed offshore units—Part 1: Procedures for calculating short-circuit currents in three-phase a.c.

IEEE Std 141™, IEEE Recommended Practice for Electric Power Distribution for Industrial Plants (*IEEE Red Book*™).[3, 4]

IEEE Std 241™, IEEE Recommended Practice for Electric Power Systems in Commercial Buildings (*IEEE Gray Book*™).

IEEE Std 242™, IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems (*IEEE Buff Book*™).

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IEEE Std 551™-2006, IEEE Recommended Practice for Calculating AC Short-Circuit Currents in Industrial and Commercial Power Systems (*IEEE Violet Book*™).

IEEE Std C37.010™, IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

IEEE Std C37.13™, IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures.

# 3. Definitions, acronyms, and abbreviations

## 3.1 Definitions

For the purposes of this document, the following terms and definitions apply. The *IEEE Standards Dictionary Online* should be consulted for terms not defined in this clause.[5]

**arcing time:** The interval of time between the instant of the first initiation of the arc and the instant of final arc extinction in all poles.

**armature:** The main current carrying winding of a machine, usually the stator.

**armature resistance:** $R_a$—The direct current armature resistance. This is determined from a dc resistance measurement. The approximate effective ac resistance is 1.2 $R_a$.

**effective resistance:** The applicable ac resistance of rotating machines for the purpose of short-circuit calculations.

NOTE—For induction machines, the approximate effective resistance is 1.2 times the armature resistance, $R_a$. For synchronous machines, the effective resistance is given as follows:[6]

$$\text{Effective resistance} = \frac{X_{2v}}{(2\pi f T_{a3})}$$

where $X_{2v}$ is the rated voltage negative sequence reactance and $T_{a3}$ is the rated voltage generator armature time constant(s). (See footnote of IEEE Std C37.010™-1999, Table 8.)

**asymmetrical current:** The combination of the symmetrical component and the direct current component of the current.

**available current:** The current that would flow if each pole of the breaking device under consideration were replaced by a link of negligible impedance without any change of the circuit or the supply.

**breaking current:** The current in a pole of a switching device at the instant of the arc initiation. Better known as *interrupting current.*

**circuit breaker:** A switching device capable of making, carrying, and breaking currents under normal circuit conditions and also making, carrying for a specified time, and breaking currents under specified abnormal conditions, such as those of short-circuit.

[5] *IEEE Standards Dictionary Online* subscription is available at: http://dictionary.ieee.org.
[6] Notes in text, tables, and figures of a standard are given for information only and do not contain requirements needed to implement this standard.

**clearing time:** The total time between the beginning of specified overcurrent and the final interruption of the circuit at rated voltage. In regard to fuses, it is the sum of the minimum melting time of a fuse, plus tolerance and the arcing time. In regard for circuit breakers, depending on types and operating mechanism, the clearing time may be made up of some or all of the following: sensing time (relay tripping time), algorithm execution time, electromechanical actuation time, mechanism operating time, and additional arcing time. Sometimes referred to as *total clearing time* or *interrupting time.*

**close and latch:** The capability of a switching device to close (allow current flow) and immediately thereafter latch (remain closed) and conduct a specified current through the device under specified conditions.

**close and latch duty:** The maximum rms value of calculated short-circuit current for medium- and high-voltage circuit breakers during the first cycle with any applicable multipliers for fault current *X/R* ratio. Often the close and latching duty calculation is simplified by applying a 1.6 factor to the calculated circuit breaker first-cycle symmetrical ac rms short-circuit current. Also called *first-cycle duty* (formerly, *momentary duty*).

**close and latch rating:** The maximum current capability of a medium or high-voltage circuit breaker to close and immediately thereafter latch closed for normal-frequency making current. The close and latch rating is 1.6 times the circuit breaker rated maximum symmetrical interrupting current in ac rms amperes, or a peak current is 2.7 times ac rms rated maximum symmetrical interrupting current. Also called *first-cycle rating* (formerly, *momentary rating*).

**contact parting time:** The interval between the time when the actuating quantity in the release circuit reaches the value causing actuation of the release and the instant when the primary arcing contacts have parted in all poles. Contact parting time is the numerical sum of release delay and opening time.

**crest current:** The highest instantaneous current during a period. *Syn:* **peak current**.

**direct axis:** The machine axis that represents a plane of symmetry in line with the no-load field winding.

**direct-axis saturated subtransient reactance:** $X''_{dv}$ (rated voltage) is the apparent reactance of the stator winding at the instant short-circuit occurs with the machine at rated voltage, no load. This reactance determines the current flow during the first few cycles after short-circuit.

**direct-axis unsaturated subtransient reactance:** $X''_{di}$ (rated current) is the reactance that is determined from the ratio of an initial reduced voltage open circuit condition and the currents from a three-phase fault at the machine terminals at rated frequency. The initial open-circuit voltage is adjusted so that rated current is obtained. The impedance is determined from the currents during the first few cycles.

**direct-axis saturated transient reactance:** $X'_{dv}$ (rated voltage) is the apparent reactance of the stator winding several cycles after initiation of the fault with the machine at rated voltage, no load. The time period for which the reactance may be considered $X'_{dv}$ can be up to a half second or longer, depending upon the design of the machine and is determined by the machine direct-axis transient time constant.

**direct-axis unsaturated transient reactance:** $X'_{di}$ (rated current) is the reactance that is determined from the ratio of an initial reduced voltage open circuit condition and the currents from a three-phase fault at the machine terminals at rated frequency. The initial open-circuit voltage is adjusted so that rated current is obtained. The initial high decrement currents during the first few cycles are neglected.

**fault:** A current that flows from one conductor to ground or to another conductor owing to an abnormal connection (including an arc) between the two. *Syn:* **short-circuit.**

**fault point angle:** The calculated fault point angle ($\tan^{-1}$[*X/R* ratio]) using complex (R + jX) reactance and resistance networks for the *X/R* ratio.

**fault point *X/R*:** The calculated fault point *X/R* ratio using separate reactance and resistance networks.

**field:** The exciting or magnetizing winding of a machine.

**first-cycle duty:** The maximum value of calculated short-circuit current for the first cycle with any applicable multipliers for fault current *X/R* ratio.

**first-cycle rating:** The maximum current capability of a piece of equipment during the first cycle of a fault.

**frequency:** The rated frequency of a circuit.

**fuse:** A device that protects a circuit by melting open its current-carrying element when an overcurrent or short-circuit current passes through it.

**high voltage:** Circuit voltages over nominal 34.5 kV.

NOTE—ANSI standards are not unanimous in establishing the threshold of "high voltage."

**impedance:** The vector sum of resistance and reactance in an ac circuit.

**interrupting current:** The current in a pole of a switching device at the instant of the arc initiation. Sometime referred to as *breaking current.*

**interrupting time:** The interval between the time when the actuating device "sees" or responds to a operating value, the opening time and arcing time. Sometimes referred to as *total break time* or *clearing time*.

**low voltage:** Circuit voltage under 1000 V.

**maximum rated voltage:** The upper operating voltage limit for a device.

**medium voltage:** Circuit voltage greater than 1000 V up to and including 34.5 kV.

NOTE—ANSI standards are not unanimous in establishing the threshold of medium voltage.

**minimum rated voltage:** The lower operating voltage limit for a device where the rated interrupting current is a maximum. Operating circuit breakers at voltages lower than minimum rated voltage restricts the interrupting current to maximum rated interrupting current.

**momentary current rating:** The maximum rms current measured at the major peak of the first cycle, which the device or assembly is required to carry. Momentary rating was used on medium- and high-voltage circuit breakers manufactured before 1965. See presently used terminology of **close and latch rating.**

**momentary current duty:** See presently used terminology of **close and latch duty.** Used for medium- and high-voltage circuit breaker duty calculations for circuit breakers manufactured before 1965.

**negative sequence:** A set of symmetrical components that have the angular phase lag from the first member of the set to the second and every other member of the set equal to the characteristic angular phase difference and rotating in the reverse direction of the original vectors. For a three-phase system, the angular different is 120°. *See also:* **symmetrical components.**

**negative sequence reactance:** $X_{2v}$ (saturated, rated voltage). The rated current value of negative sequence reactance is the value obtained from a test with a fundamental negative sequence current equal to rated armature current (of the machine). The rated voltage value of negative sequence reactance is the value obtained from a line-to-line short-circuit test at two terminals of the machine at rated speed, applied from no load at rated voltage, the resulting value being corrected when necessary for the effect of harmonic components in the current.

**offset current:** A current waveform whose baseline is offset from the ac symmetrical current zero axis.

**opening time:** The time interval between the time when the actuating quantity of the release circuit reaches the operating value, and the instant when the primary arcing contacts have parted. The opening time includes the operating time of an auxiliary relay in the release circuit when such a relay is required and supplied as part of the switching device.

**peak current:** The highest instantaneous current during a period.

**positive sequence:** A set of symmetrical components that have the angular phase lag from the first member of the set to the second and every other member of the set equal to the characteristic angular phase difference and rotating in the same phase sequence of the original vectors. For a three-phase system, the angular different is 120°. *See also:* **symmetrical components**.

**positive sequence machine resistance:** $R_1$ is that value of rated frequency armature resistance that, when multiplied by the square of the rated positive sequence armature current and by the number of phases, is equal to the sum of the copper loss in the armature and the load loss resulting from the flow of that current. This is **NOT** the resistance to be used for the machine in short-circuit calculations.

**quadrature axis:** The machine axis that represents a plane of symmetry in the field that produces no magnetization. This axis is 90° ahead of the direct axis.

**quadrature-axis saturated subtransient reactance:** $X''_{qv}$ (rated voltage) same as $X''_{dv}$ except in quadrature axis.

**quadrature-axis unsaturated subtransient reactance:** $X''_{qi}$ (rated current) same as $X''_{di}$ except in quadrature axis.

**quadrature-axis unsaturated transient reactance:** $X_q$ (rated current) is the ratio of reactive armature voltage to quadrature-axis armature current at rated frequency and voltage.

**quadrature-axis saturated transient reactance:** $X'_{qv}$ (rated voltage) same as $X'_{\mathrm{dv}}$ except in quadrature axis.

**quadrature-axis unsaturated transient reactance:** $X'_{\mathrm{qi}}$ (rated voltage) same as $X'_{\mathrm{di}}$ except in quadrature axis.

**rating:** The designated limit(s) of the operating characteristic(s) of a device. These data are usually on the device nameplate.

**rms:** The square root of the average value of the square of the voltage or current taken throughout one period. In this text, rms will be considered total rms unless otherwise noted.

**rms ac:** The square root of the average value of the square of the ac voltage or current taken throughout one period.

**rms, single cycle:** *See:* **single-cycle rms**.

**rms, total:** *See:* **total rms**.

**rotor:** The rotating member of a machine.

**short-circuit:** An abnormal connection (including arc) of relative low impedance, whether made accidentally or intentionally, between two points of different potentials. *Syn:* **fault**.

**short-circuit duty:** The maximum value of calculated short-circuit current for either first-cycle current or interrupting current with any applicable multipliers for fault current $X/R$ ratio or decrement.

**single-cycle rms:** The square root of the average value of the square of the ac voltage or current taken throughout one ac cycle.

**stator:** The stationary member of a machine.

**symmetrical:** That portion of the total current that, when viewed as a waveform, has equal positive and negative values over time, such as the form exhibited by a pure, single frequency sinusoidal waveform.

**symmetrical components:** A symmetrical set of three vectors used to mathematically represent an unsymmetrical set of three-phase voltages or currents. In a three-phase system, one set of three equal magnitude vectors displaced from each other by 120° in the same sequence as the original set of unsymmetrical vectors. This set of vectors is called the positive sequence component. A second set of three equal magnitude vectors displaced from each other by 120° in the reverse sequence as the original set of unsymmetrical vectors. This set of vectors is called the negative sequence component. A third set of three equal magnitude vectors displaced from each other by 0°. This set of vectors is called the *zero sequence component*.

**synchronous reactance:** Direct axis $X_d$ (unsaturated, rated current) is the self-reactance of the armature winding to the steady-state balanced three-phase positive sequence current at rated frequency and voltage in the direct axis. It is determined from an initial open-circuit voltage and a sustained short-circuit on the synchronous machine terminals.

**time constant, rated voltage three-phase short-circuit armature ($T_{a3}$):** $T_{a3}$ is the time constant representing the decay of the machine currents to a suddenly applied three-phase short-circuit to the terminals of a machine initially at rated voltage, rated speed, and no load.

**total break time:** The interval between the time when the actuating quantity of the release circuit reaches the operating value, the switching device being in a closed position, and the instant of arc extinction on the primary arcing contacts. Total break time is equal to the sum of the opening time and arcing time. Better known as **interrupting time**.

**total clearing time:** *See:* **clearing time** or **interrupting time**.

**total rms:** The square root of the average value of the square of the ac and dc voltage or current taken throughout one period.

**voltage, high:** *See:* **high voltage**.

**voltage, low:** *See:* **low voltage**.

**voltage, medium:** *See:* **medium voltage**.

**voltage range factor:** The voltage range factor, *K*, is the range of voltage to which the circuit breaker can be applied where *EI* equals a constant. *K* equals the maximum rated operating voltage divided by the minimum rated operating voltage.

***X/R* ratio:** The ratio of rated frequency reactance and effective resistance to be used for short-circuit calculations. Approximately equal to $\frac{X_{2v}}{1.2R_a}$ or $2\pi f T_{a3}$.

**zero sequence:** A set of symmetrical components that have the angular phase lag from the first member of the set to the second and every other member of the set equal to 0° and rotating in the same direction as the original vectors. *See also:* **symmetrical components**.

**30-cycle time:** A time 30 cycles after the actuating quantity of the release circuit reaches the operating value. After this time period, the ac decaying component of a fault current is considered to be negligible.

## 3.2 Acronyms and abbreviations

The following are the symbols and their definitions that are used in this standard.

| | |
|---|---|
| a | symmetrical component operator = 120° |
| $e$ | instantaneous voltage |
| $e_o$ | initial voltage |
| $E$ | rms voltage |
| $E_{max}$ | peak or crest voltage |
| $E_{LN}$ | rms line-to-neutral voltage |
| $E_{LL}$ | rms line-to-line voltage |
| $f$ | frequency in Hertz |
| $i$ | instantaneous current |
| $i_{dc}$ | instantaneous dc current |
| $i_{ac}$ | instantaneous ac current |
| $I$ | rms current |
| $I_{max}$ | peak or crest current |
| $I_{max,s}$ | symmetrical peak current |
| $I_{max,ds}$ | decaying symmetrical peak current |
| $I'$ | rms transient current |
| $I''$ | rms subtransient current |

| | |
|---|---|
| $I'_{dd}$ | interrupting duty current |
| $I''_{dd}$ | first-cycle duty current |
| $I_{SS}$ | rms steady-state current |
| j | 90° rotative operator, imaginary unit |
| $L$ | inductance |
| $Q$ | electric charge |
| $R$ | resistance |
| $R_a$ | armature resistance |
| $t$ | time |
| $T_{a3}$ | three-phase short-circuit armature time constant |
| $X$ | reactance |
| $X'_d$ | transient direct-axis reactance |
| $X''_d$ | subtransient direct-axis reactance |
| $X'_q$ | transient quadrature-axis reactance |
| $X''_q$ | subtransient quadrature-axis reactance |
| $X_{2v}$ | negative sequence reactance |
| $Z$ | impedance: $Z = R + jX$ |
| $\alpha$ | $\tan^{-1}(\omega L/R) = \tan^{-1}(X/R)$ |
| $\phi$ | phase angle |
| $\omega$ | angular frequency: $\omega = 2\pi f$ |
| $\tau$ | intermediate time |
| $\theta$ | phase angle difference |

# 4. Introduction

## 4.1 Overview

Conducting thorough and detailed short-circuit studies and analysis of industrial and commercial power systems is of critical importance. Electric power systems in industrial plants and commercial and institutional buildings are designed to serve loads in a safe and reliable manner. One of the major considerations in the design of a power system is adequate control of short-circuits or *faults* as they are commonly called. Uncontrolled short-circuits can cause service outage with accompanying production downtime and associated inconvenience, interruption of essential facilities or vital services, extensive equipment damage, personnel injury or fatality, and possible fire damage.

Short-circuits are caused by faults in the insulation of a circuit, and in many cases an arc ensues at the point of the fault. Such an arc may be destructive and may constitute a personnel arc-flash hazard or a structure fire hazard. Prolonged duration of arcs, in addition to the heat released, may result in transient overvoltages that may endanger the insulation of equipment in other parts of the system. Faults can also be caused by accidental contact or too small a separation between live conductors or between live conductors and ground. Arcing faults, specifically at low voltage, may be significantly lower in magnitude than calculated maximum bolted faults. Clearly, the fault must be quickly removed from the power system, and this is the job of the circuit protective devices—the circuit breakers and fusible switches.

A short-circuit current generates heat that is proportional to the square of the current magnitude, $I^2R$. The large amount of heat generated by a short-circuit current may damage the insulation of rotating machinery and apparatus which is connected in the faulted system, including cables, transformers, switches, and circuit breakers. The most immediate danger involved in the heat generated by short-circuit currents is permanent destruction of insulation. This may be followed by actual fusion of the conducting circuit, with resultant additional arcing faults.

The heat that is generated by high short-circuit currents tends not only to impair insulating materials to the point of permanent destruction, but also exerts harmful effects upon the contact members in interrupting devices.

The small area common between two contact members that are in engagement depends mainly upon the hardness of the contact material and upon the amount of pressure by which they are kept in engagement. Owing to the concentration of the flow of current at the points of contact engagement, the temperatures of these points reached at the times of peak current are very high. As a result of these high-spot temperatures, the material of which the contact members are made may soften. If, however, the contact material is caused to melt by excessive $I^2R$ losses, there is an imminent danger of welding the contacts together, rendering it impossible to separate the contact members when the switch or circuit breaker is called upon to open the circuit. Since it requires very little time to establish thermal equilibrium at the small points of contact engagement, the temperature at these points depends more upon the peak current than upon the rms current. If the peak current is sufficient to cause the contact material to melt, solidification may occur immediately upon decrease of the current from its peak value.

Other important effects of short-circuit currents are the strong electromagnetic forces of attraction and repulsion to which the conductors are subjected when short-circuit currents are present. These forces are proportional to the square of the current and may subject any rotating machinery, transmission, and switching equipment to severe mechanical stresses and strains. The strong electromagnetic forces that high short-circuit currents exert upon equipment can cause deformation in rotational machines, transformer windings, and equipment bus bars, which may fail at a future time. Deformation in circuit breakers and switches will cause alignment and interruption difficulties.

Modern interconnected systems involve the operation in parallel of large numbers of synchronous machines, and the stability of such an interconnected system may be greatly impaired if a short-circuit in

any part of the system is allowed to prevail. The stability of a system requires short fault-clearing times and can be more limiting than the longer time considerations imposed by thermal or mechanical effects on the equipment.

## 4.2 Objectives for short-circuit analysis

Due to the severe impact that a short-circuit can cause to power system operation and safety of equipment and personnel, a fault in a system must be automatically detected and removed from the system as soon as possible. This requires extensive studies of system conditions under a fault. The system behavior under a short-circuit can be studied by short-circuit analysis or dynamic simulation. A dynamic simulation solves a set of algebraic and differential equations representing dynamic characteristics of rotating machines and their control systems. The dynamic simulation requires detailed modeling of system equipment, especially synchronous generators including governor and exciter, etc. It provides detailed short-circuit current waveforms. However, the equipment data required to perform dynamic simulation of short-circuit is often not readily available and therefore this type of study is not commonly used. The dynamic simulation of short-circuit is beyond the scope of this standard.

The short-circuit analysis is quasi-static study. It determines the total fault current and fault current contributions throughout the system, including contribution sources, such as power grid, synchronous generator, synchronous motor, and induction motors. In the short-circuit analysis, contributing sources are represented by approximate models to calculate the maximum possible fault current values for protection device evaluation or selection. Minimum fault current, arcing fault current, and fault current under other conditions can also be determined in short-circuit analysis. The calculation results are used in determining protective device settings and arc flash incident energy.

The results from a short-circuit analysis are required in the design of new systems and in analysis of existing systems. In the design of a new system, they are used to size equipment ratings, such as bus bars, cables, transformers, and protective devices. For an existing system, the short-circuit analysis results are used to verify acceptable equipment ratings. The following are objectives for short-circuit analysis:

a) Verify the protective device closing and latching capability.

b) Verify the protective device interrupting capability.

c) Verify the equipment's ability to withstand large mechanical forces caused by the maximum short-circuit capacity.

d) Verify the equipment's ability to withstand thermal stress based on $I^2t$ values.

e) Determine branch fault currents under various conditions as required to determine protective relay settings and associated equipment ratings.

f) Determine short-circuit currents necessary for the calculation of arc fault incident energy (IEEE Std 1584™-2002 [B46]).

## 4.3 Methodology and standards

There are a number of standards for short-circuit analysis adopted by different organizations in the world, such as ANSI/IEEE standards, IEC standards, Russian standards (GOST), Chinese standards (GB), etc. The basic methods for short-circuit calculations are very similar, but with differences in modeling of various types of equipment and considerations of system prefault operating conditions. This standard will provide a detailed description based on the ANSI/IEEE and IEC standards, primarily due to their most eminent influence in the world. Clause 2 lists several IEEE and IEC standards that are indispensable for the application of this document.

# 5. Description of short-circuit current

## 5.1 Introduction

Electric power systems are designed to be as fault-free as possible through careful system and equipment design, proper equipment installation, and periodic equipment maintenance. However, even when these practices are followed, faults do occur. Some of the causes of faults are:

a) Presence of animals, such as birds and insects, in equipment
b) Loose connections causing equipment overheating
c) Voltage surges
d) Deterioration of insulation due to age
e) Voltage or mechanical stresses applied to the equipment
f) Accumulation of moisture or other contaminants
g) The intrusion of metallic or conducting objects into the equipment, such as grounding clamps, fish tape, tools, jackhammers, or pay-loaders
h) A large assortment of "undetermined causes"
i) Over-dutied equipment
j) Human error during installation or maintenance work
k) Inadequate cooling
l) Natural disasters (heavy rain or wind storms, floods, etc.)

When a short-circuit occurs in an electric power distribution system, several things can happen, such as:

- The short-circuit currents may be very high, introducing a significant amount of energy into the fault.
- At the fault location, arcing and burning can occur damaging adjacent equipment and also possibly presenting an arc flash hazard to personnel working on the equipment.
- Short-circuit current may flow from the various rotating machines in the electrical distribution system to the fault location.
- All components carrying the short-circuit currents will be subjected to thermal and mechanical stresses due to current flow. This stress varies as a function of the magnitude of the current squared and the duration of the current flow ($I^2t$) and may damage these components.
- System voltage levels drop in proportion to the magnitude of the short-circuit currents flowing through the system elements. Maximum voltage drop occurs at the fault location (down to zero for a bolted fault), but all parts of the power system will be subject to a voltage drop to some degree.

## 5.2 Available short-circuit current

The *available* short-circuit current is defined as the maximum possible value of short-circuit current that may occur at a particular location in the distribution system assuming that no fault-related influences, such as fault arc impedances, are acting to reduce the fault current. The available short-circuit current is directly related to the size and capacity of the power sources (utility, generators, and motors) supplying the system and is typically independent of the load current of the circuit. The larger the capacity of the power sources supplying the system, the greater the available short-circuit current (generally). The main factors

determining the magnitude and duration of the short-circuit currents are the type of fault, fault current sources present, and the impedances between the sources and the point of the short-circuit. The characteristics, locations, and sizes of the fault current sources connected to the distribution system at the time the short-circuit occurs have an influence on both the initial magnitude and the wave shape of the fault current.

Alternating current (ac) synchronous and induction motors, generators, and utility ties are the predominant sources of short-circuit currents. At the time of the short-circuit, synchronous and induction motors will act as generators and will supply current to the short-circuit based on the amount of stored electrical energy in them. In an industrial plant, motors often contribute a significant share of the total available short-circuit current.

## 5.3 Symmetrical and asymmetrical currents

The terms *symmetrical* current and *asymmetrical* current describe the shape of the ac current waveforms about the zero axis. If the envelopes of the positive and negative peaks of the current waveform are symmetrical around the zero axis, they are called *symmetrical current* envelopes (Figure 1). The envelope is a line drawn through the peaks or crests of the waves.

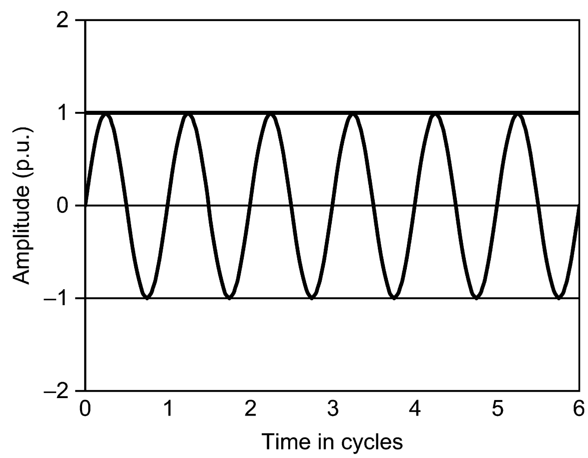



**Figure 1—Symmetrical ac waveform**

If the envelopes of positive and negative peaks are not symmetrical around the zero axis, they are called *asymmetrical current* envelopes. Figure 2 shows a fully offset (non-decaying) fault current waveform. The amount of offset that will occur in a fault current waveform depends on the time at which the fault occurs on the ac voltage waveform and the network resistances and reactances. The current in a purely reactive network could have any offset from none to fully offset, depending on the time of its inception, and the offset would be sustained (not decaying). A fault occurring in a purely resistive system would have no offset in the current waveform. A network containing both resistances and reactances will generally begin with some offset in the current (up to peak ac value) and gradually the current will become symmetrical (because of the decay of the offset) around the zero axis.

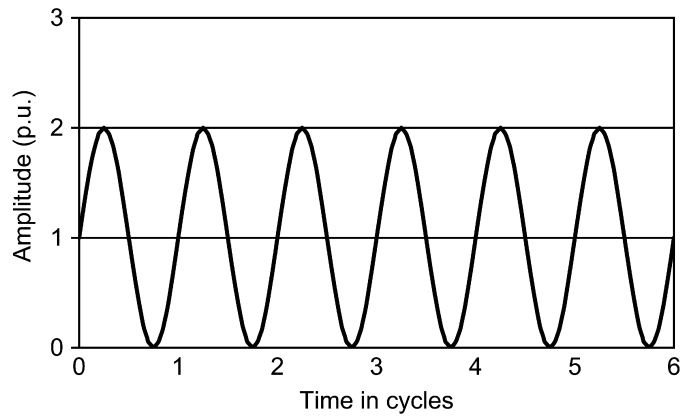



**Figure 2—Totally offset ac waveform**

As stated previously, induction and synchronous machines connected to the system supply current to the fault and, because of the limited amount of stored electrical energy in them, their currents decay with time. Figure 3 shows the symmetrical portion of a decaying fault current waveform typical for such equipment.

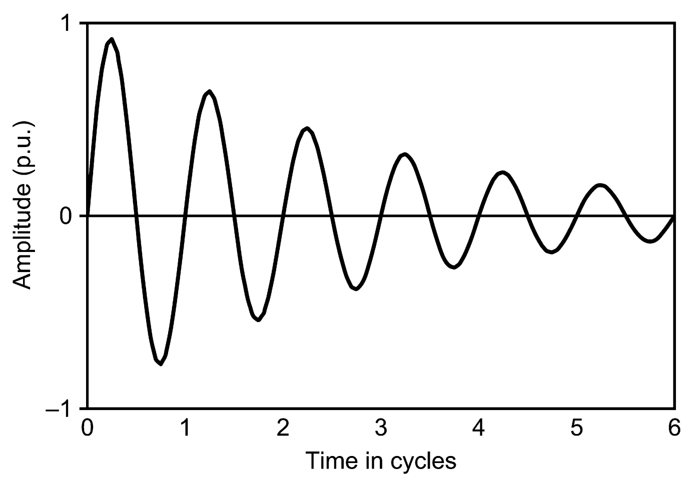



**Figure 3—Decaying symmetrical ac waveform**

Short-circuit currents are nearly always asymmetrical during the first few cycles after the short-circuit occurs and contain both dc and ac components. The dc component is shown in Figure 4. The asymmetrical current component (dc) is always at a maximum during the first cycle after the short-circuit occurs. This dc component gradually decays to zero. A typical asymmetrical short-circuit current waveform is shown in Figure 5.

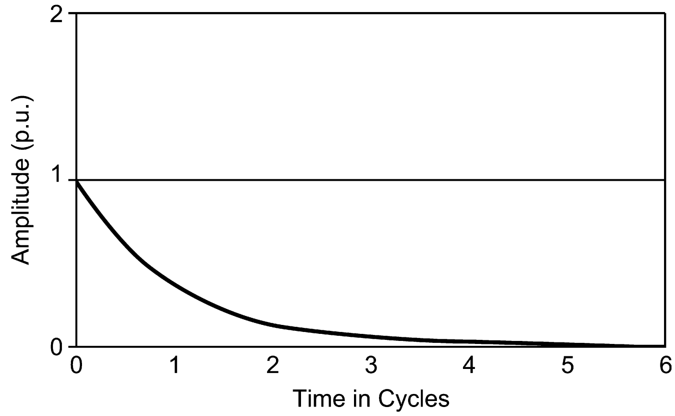



**Figure 4—Decaying dc waveform**

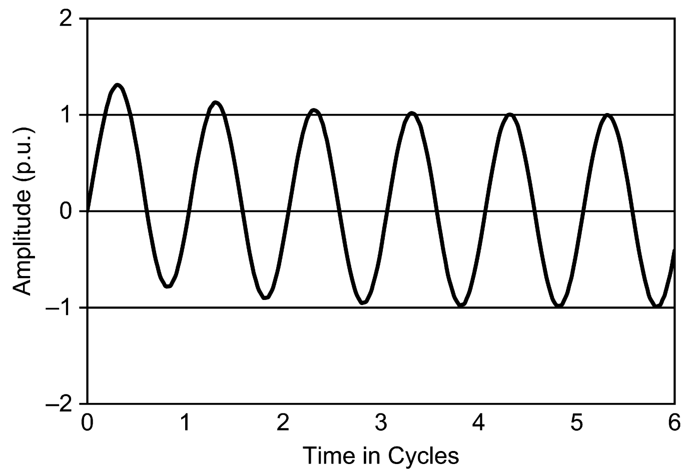



**Figure 5—Asymmetrical fault current ac waveform**

## 5.4 Short-circuit calculations

The calculation of the precise magnitude of a short-circuit current at a given time after the inception of a fault is a rather complex computation. Consequently, simplified methods have been developed that yield conservative calculated short-circuit currents that may be compared with the assigned (tested) fault current ratings of various system overcurrent protective devices. Figure 6 provides a means of understanding the shape of the fault current waveform, and consequently the fault current magnitude at any point in time. The circuit consists of an ideal sinusoidal voltage source and a series combination of a resistance, an inductance, and a switch. The fault is initiated by the closing of the switch. The value of the rms symmetrical short-circuit current, $I$, is determined through the use of the proper impedance in Equation (1):

$$I = \frac{E}{Z} \tag{1}$$

where

- $E$ is the rms driving voltage
- $Z$ (or $X$) is the Thevenin equivalent system impedance (or reactance) from the fault point back to and including the source or sources of short-circuit currents for the distribution system

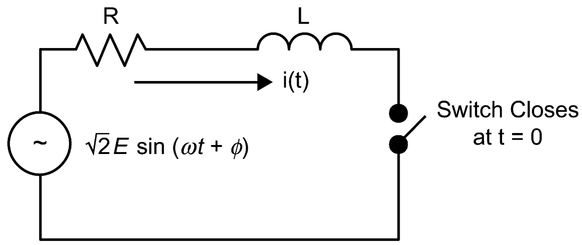



**Figure 6—Circuit model for asymmetry**

One simplification that is made is that all machine internal voltages are the same. In reality, the equivalent driving voltages used are the internal voltages of the electrical machines where each machine has a different voltage based on loading and impedance. During a fault, the machine's magnetic energy or its internal voltage is reduced faster than it can be replaced by energy supplied by the machine's field. This results in a decay (gradual reduction) of driving voltage over time. The rate of decay differs for each source. The resistance and reactance of machines is a fixed value based on the physical design of the equipment. Solving a multi-element system with many varying voltage sources becomes cumbersome. The same current can be determined by holding the voltage fixed and varying the machine impedance with time. This interchange helps to simplify the mathematics. The value of the impedance that must be used in these calculations is determined with regard to the basis of rating for the protective device or equipment under consideration. Different types of protective devices or equipment require different machine impedances to determine the fault current duty. Equipment evaluated on a first-cycle criteria would use a lower machine impedance and hence a higher current than equipment evaluated on an interrupting-time basis (1.5 to 8 cycles), which uses a higher impedance.

The determination of how the fault current behaves as a function of time involves expansion of Equation (1) and the solution of Equation (2) for current $i$:

$$Ri + L\frac{di}{dt} = \sqrt{2}E\sin\left(\omega t + \alpha\right) \tag{2}$$

where

| | |
|---|---|
| $E$ | is the rms magnitude of the sinusoidal voltage source |
| $i$ | is the instantaneous current in the circuit at any time after the switch is closed |
| $R$ | is the circuit resistance in ohms |
| $L$ | is the circuit inductance in Henries (equal to the circuit reactance divided by ω) |
| $t$ | is time in seconds |
| $\alpha$ | is the angle of the applied voltage in radians when the fault occurs |
| $\omega$ | is $2\pi f$ where $f$ is the system frequency in hertz (Hz) |

The details of the solution of Equation (2) are well-covered in electric power textbooks, so only the solution of the equation will be stated here. Assuming the prefault current through the circuit to be zero (i.e., load current = 0), then the instantaneous current solution to Equation (2) is

$$i = -\frac{\sqrt{2}E}{Z}\sin\left(\alpha - \phi\right)e^{-\frac{\omega tR}{X}} + \frac{\sqrt{2}E}{Z}\sin\left(\omega t + \alpha - \phi\right) \tag{3}$$

$$i = -i_{dc}\sin\left(\alpha - \varphi\right)e^{-\frac{\omega Rt}{X}} + \sqrt{2}I_{ac,rms}\sin\left(\omega t + \alpha - \varphi\right) \tag{4}$$

where

$$\varphi = \tan^{-1}\left(\frac{\omega L}{R}\right) = \tan^{-1}\left(\frac{X}{R}\right)$$
$$X = \omega L$$
$$Z = \sqrt{R^2 + X^2}$$

If time $t$ is expressed in cycles, Equation (4) becomes

$$i = -i_{dc}\sin(\alpha - \varphi)e^{-\frac{2\pi Rt}{X}} + \sqrt{2}I_{ac,rms}\sin(2\pi t + \alpha - \varphi) \tag{5}$$

The first term in Equation (3) represents the transient dc component of the solution. The initial magnitude $\sqrt{2}\,E/Z \times \sin(\alpha - \phi)$ decays in accordance with the exponential expression. This dc component eventually disappears. The second term represents the steady-state ac component of the solution. The second term is a sinusoidal function of time whose crest value is simply the maximum peak value of the supply voltage divided by the magnitude of the Thevenin equivalent system impedance ($\sqrt{2}\,E/Z$) as viewed from the fault. The difference between the initial fault current magnitude and the final steady-state fault current magnitude depends only on the $X/R$ ratio of the circuit impedance and the phase angle $\alpha$ of the supply voltage when the fault occurs. Note that at time zero the dc component of fault current is exactly equal in magnitude to the value of the ac fault current component, but opposite in sign. This condition must exist due to the fact that the initial current in the circuit is zero and the fact that current cannot change instantaneously in the inductive circuit of Figure 6.

The significance of the transient and steady-state components of the fault current is best illustrated by considering an actual example. Figure 5 shows the response of a specific circuit with an $X/R$ ratio of 7.5. The circuit is supplied by a 60 Hertz source ($\omega = 377$), with the fault occurring (switch closes) when the voltage is at $\alpha = 58°$. The plot of the current is obtained from the general solution of Equation (3).

## 5.5 Total short-circuit current

The total short-circuit current available in a distribution system is usually supplied from a number of sources, which can be grouped into three main categories. The first is the utility transmission system supplying the facility, which acts like a large, remote generator. The second includes "local" generators, either in the plant or nearby in the utility. The third source category is synchronous and induction motors, which are located in many plants and facilities. All these are rotating machines; those of the second and third categories have machine currents that decay significantly with time due to reduction of flux in the machine during a short-circuit. For a short-circuit at its terminals, the induction motor symmetrical current disappears entirely after one to twelve cycles, while the current of a synchronous motor is maintained at a lower initial value by its energized field. Networks having a greater proportion of induction motors to synchronous motors will have quicker decays of ac short-circuit current components. The fault current magnitude during the first few cycles is further increased by the dc fault current component (Figure 4). This component also decays with time, increasing the difference in short-circuit current magnitude between the first cycle after the short-circuit occurs and a few cycles later.

The total short-circuit current that has steady-state ac, decaying ac, and decaying dc current components can be expressed as shown in Equation (6). Figure 7 shows the circuit diagram and Figure 8 shows the response curve corresponding to Equation (6). Although decaying sources are not usually shown in equivalent circuits, a separate decaying source has been shown in Figure 7 to assist the reader with understanding the interactions that occur in real world applications.

$$i = i_{dc\,decay} + i_{ac\,steady\,state} + i_{ac\,decay} \tag{6}$$

with

$$i_{dc\,decay} = (I_{ac\,steady\,state})\sin(\alpha - \varphi)e^{-\frac{R\omega t}{X}}$$

$$i_{ac\,steady\,state} = \sqrt{2}I_s \sin(\omega t + \alpha - \varphi)$$

$$i_{ac\,decay} = \sqrt{2}I_{ds} \sin(\omega t + \alpha - \varphi)e^{-kt}$$

where

- $I_s$ is the symmetrical steady-state rms current magnitude
- $I_{ds}$ is the decaying symmetrical rms current magnitude
- $k$ is a variable depending upon the mix and size of rotational loads
- $t$ is in seconds

The magnitude and duration of the asymmetrical current depends upon the following two parameters:

- The *X/R* ratio of the faulted circuit
- The phase angle of the voltage waveform at the time the short-circuit occurs

The greater the fault point *X/R* ratio, the longer the asymmetrical fault current decay time. For a specific *X/R* ratio, the angle of the applied voltage at the time of short-circuit initiation determines the degree of fault current asymmetry that will exist for that *X/R* ratio.

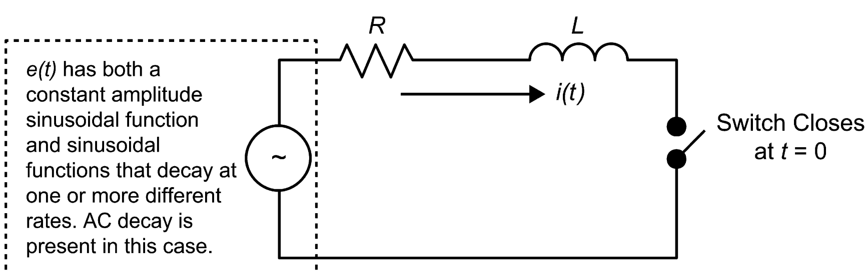



**Figure 7—Circuit model with steady-state and decaying ac current sources**

In a purely inductive circuit, the maximum dc current component is produced when the short-circuit is initiated at the instant the applied voltage is zero ($\alpha = 0°$ or 180° when using sine functions). The current will then be fully offset in either the positive or negative direction. Maximum asymmetry for any circuit *X/R* ratio often occurs when the short-circuit is initiated near voltage zero. The initial dc fault current component is independent of whether the ac component remains constant or decays from its initial value.

For any circuit *X/R* ratio, the voltage and current waveforms will be out of phase from each other by an angle corresponding to the amount of reactance in the circuit compared to the amount of resistance in the circuit. This angle is equal to $\tan^{-1}(2\pi f \times L/R)$. For a purely inductive circuit, the current waveform will be displaced from the voltage waveform by 90° (lagging). As resistance is added to the circuit this angular displacement will decrease to zero. In a purely resistive circuit, the voltage and current will be completely in-phase and without an offset.

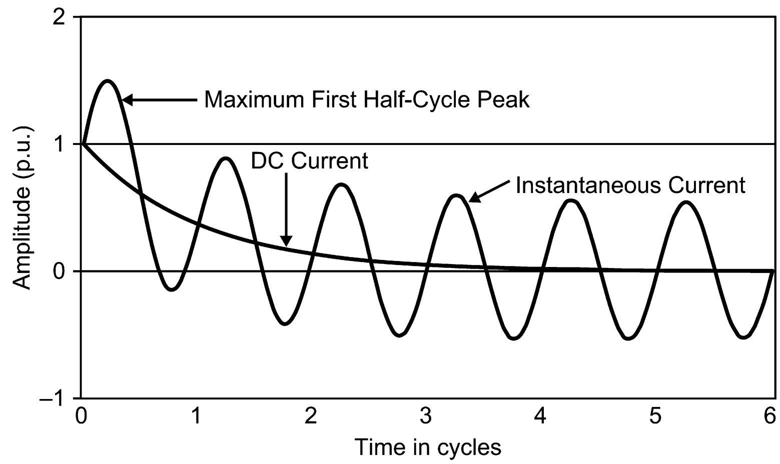



**Figure 8—Asymmetrical ac short-circuit current made up of dc, decaying ac, and symmetrical ac current**

## 5.6 Why short-circuit currents are asymmetrical

If a short-circuit occurs at the peak of the voltage waveform in a circuit containing only reactance, the short-circuit current will start at zero and trace a sine wave that will be symmetrical about the zero axis (Figure 1). If a short-circuit occurs at a voltage zero, the current will start at zero, but cannot follow a sine wave symmetrically about the zero axis because in an inductive circuit the current must lag the applied voltage by 90°. This can happen only if the current is displaced from the zero axis as shown in Figure 2. The two cases shown in Figure 1 and Figure 2 represent the extremes. One represents a totally symmetrical fault current; the other represents a completely asymmetrical current. If the fault occurs at any point between a voltage zero and a voltage crest, the current will be asymmetrical to some degree depending upon the point at which the short-circuit occurs on the applied voltage waveform. In a circuit containing both resistance and reactance, the degree of asymmetry can vary between zero and the same fully offset limits as a circuit containing only reactance. However, the point on the applied voltage waveform at which the short-circuit must occur to produce maximum fault current asymmetry depends upon the ratio of circuit reactance to circuit resistance.

## 5.7 DC component of short-circuit currents

Short-circuit currents are analyzed in terms of two components—a symmetrical current component and the total current that includes a dc component as shown in Figure 1 and Figure 4, respectively. As previously discussed, the asymmetrical fault current component is at a maximum during the first cycle of the short-circuit and decays to a steady-state value due to the corresponding changes of the magnetic flux fields in the machine. In all practical circuits containing resistance and reactance, the dc component will also decay to zero as the energy represented by the dc component is dissipated as $I^2R$ heating losses in the circuit. The rate of decay of the dc component is a function of the resistance and reactance of the circuit. In practical circuits, the dc component decays to zero in one to 30 cycles.

## 5.8 Significance of current asymmetry

Current asymmetry is significant for two important reasons. First is the electromagnetic force exerted on equipment parts carrying the current, and second is the thermal energy content of the fault current. The peak characteristics of both the magnetic forces and the thermal heating are a function of the square of the

current, $i^2$. In Figure 8 the first peak of the asymmetrical fault current waveform has a magnitude that is approximately 1.5 times the crest value of the steady-state waveform. At the first current peak, the magnetic forces exerted on current-carrying equipment by the asymmetrical fault current are about 2.25 times the peak forces that would be caused by symmetrical fault current during the first cycle. In addition, these large values do not immediately vanish. Consequently, the $i^2t$ (thermal or heating effect) content of the current is also much greater. Magnetic forces and heating affect the design and application of the protective equipment used on a power system.

This is where the significance of current asymmetry lies. In designing and applying devices that will be exposed to fault currents, the transient (asymmetrical) as well as the steady-state fault currents magnitudes must be considered, because both the mechanical forces and the thermal effects placed on protective equipment can be greatly magnified in the initial fault current period.

## 5.9 The application of current asymmetry information

In the previous discussion, a single-phase current was examined to give an understanding of asymmetry. In a three-phase system with a bolted three-phase fault, the sum of the current at any point in time in the three phases must add to zero. Therefore, if one phase has a maximum offset, then the other two phases must have a negative offset to balance current. The decay time constant of all phases is the same.

The maximum magnetic force produced on a circuit element, such as a circuit breaker, occurs at the instant the fault current through the circuit element is at a maximum. From an equipment design and application viewpoint, the phase with the largest of the fault current peaks is of particular interest. This current value subjects the equipment to the most severe magnetic forces. The largest fault current peak typically occurs in the first current cycle when the initiation of the short-circuit current is near or coincident with the applied voltage passing through zero. This condition is called the *condition of maximum asymmetry*.

In the application of equipment that can carry fault current—such as circuit breakers, switches, transformers, and fuses—the total available short-circuit current must be determined. For correct equipment application, knowledge of the maximum test *X/R* ratio or minimum power factor of the applied fault current used in the acceptance test by ANSI, NEMA, UL, or other standard is also required. Peak fault current magnitudes are significant for some devices, such as low-voltage circuit breakers, while asymmetrical rms current magnitudes are equally significant for high-voltage circuit breakers. This leads to the need to develop an *X/R* ratio dependent short-circuit calculation for proper comparison to the equipment being applied. The fault current calculation needs to take into account the ac component and the transient dc component of the calculated fault current to determine the total maximum peak or rms current magnitude that can occur in a circuit. When the calculated fault *X/R* ratio is greater than the equipment test *X/R* ratio, the higher total fault current associated with the higher *X/R* ratio must be taken into account when evaluating the application of the equipment.

The references (Alm [B1], Close [B9], Guillemin [B13], Reichenstein and Gomez [B56], Stevenson [B60], and Wagner [B63]) show that the effects of the peak fault current magnitude and the energy content of the first current cycle are much greater than the effect of the rms value. For the condition of maximum asymmetry, the rms value of the first-cycle fault current theoretically can be as great as 1.732 times the steady-state rms symmetrical fault current component. However, the peak first-cycle current for the same condition can be up to two times the peak of the steady-state current component, and the magnetic forces can be four times that of the rms symmetrical ac component. From the equipment design viewpoint, these peak currents and energy comparisons are the maximum that the equipment must withstand. For ANSI rated equipment, the maximum asymmetrical rms current provides this measure of maximum capability.

It is important to know the terms defining the characteristic short-circuit current waveforms. The test short-circuit currents used for circuit breaker and fuse interrupting ratings have different test procedures and power factor (*X/R* ratios) requirements. For example, high-voltage power circuit breakers use rms current interrupting tests at a power factor of 6.7% (*X/R* = 15), while low-voltage circuit breakers use peak currents

at a power factor of 15% (*X/R* = 6.59). Molded case and insulated case circuit breakers have different (from 6.7% and 15%) test power factors that must be considered. If the calculated fault point *X/R* ratio is greater than the test *X/R* ratio of the interrupting device, then the calculation of equipment duty current is affected. The duty current calculation is covered in Clause 9.

## 5.10 Maximum peak current

After a bolted three-phase fault is initiated, the maximum peak current occurs in one phase during the first half-cycle, and is often assumed, usually erroneously, to occur when the symmetrical ac current component is at its peak. The familiar first half-cycle current assumption suggests that the highest first-cycle peak current also occurs at the first half-cycle in the phase that has the maximum initial dc component. This is also erroneous, except for faults that occur on purely inductive circuits, where the resistance is zero. For circuits with resistance, the absolute maximum fault current peak occurs before the symmetrical current peak and before one half-cycle as shown on Figure 9. Figure 9 is drawn for fault in a circuit with a relatively low *X/R* ratio of 2 to emphasize these important characteristics. This analysis assumes fundamental 60 Hertz voltage, linear impedances, no ac decaying sources, and no prefault load currents. The largest of these fault current peaks can be found mathematically by differentiating the current expression in Equation (3) with respect to its two independent variables $t$ and $\alpha$, The other variables $E$, $R$, $X$, and $\omega$ are fixed for any given circuit. Differentiating the expression shows the largest fault current peak occurs for zero voltage angle $\alpha$. In this situation, the largest peak occurs in the first current cycle, so the current waveform resembles that shown in Figure 9.

Important characteristics shown in Figure 9 are as follows:

a) The short-circuit starts at zero voltage.

b) The initial asymmetrical current is zero, due to the assumption of no prefault load current and item c) below.

c) At the instant of fault initiation, the dc fault current value is equal in magnitude of the ac fault current value but opposite in sign.

d) The maximum fault current peak occurs before the first positive symmetrical fault current peak.

The maximum peak current is obtained by Equation (3) using an iterative approach and results in maximum peak and maximum rms currents multipliers as shown in Table 1 and Table 2. The values listed under the column headed *Exact* of Table 1 and Table 2 have been calculated from the equation and are theoretically exact.

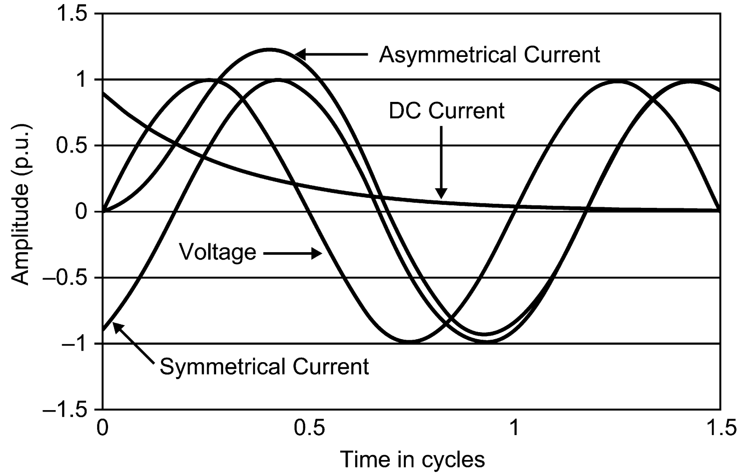



**Figure 9—Maximum peak asymmetrical short-circuit current**

For circuit *X/R* ratios between 0.5 and 1000, the second column in Table 1 and Table 2 shows the time in cycles at which the maximum peak and maximum rms currents occur. Note that the rms value of a function is based on an average, over one period, of the function squared. Strictly speaking, a non-periodic function does not have an rms value, because no period exists over which to determine an average. When the function consists of a sinusoidal component and an exponentially-decaying dc term as is commonly found in power systems, it is common practice to use the dc value at the half-cycle point in calculations of the total rms current. It should be noted that this half-cycle value does not necessarily correspond to the peak value of the total asymmetrical current. The use of the dc value evaluated at half-cycle is, however, very widely accepted and is the basis for numerous standards relating to short-circuits and protective equipment.

Because the current is lagging the applied voltage by the angle of $\tan^{-1}$ (*X/R*), the peak current occurs before one half-cycle. Only in a pure reactance circuit (*X/R* equals infinity) does the peak occur at the one half-cycle. Figure 9 illustrates a typical circuit where the peak occurs before the first half-cycle. The figure represents a circuit having a fault point *X/R* equal to 2.0 with the peak current occurring at approximately 0.40 cycles and a magnitude equal to 1.242 times the ac symmetrical peak current.

Calculating the peak current at a time of one half-cycle on a 60 Hertz base by using Equation (7) yields a non-conservative (lower than Exact) value for the peak current. The peak current multipliers for the one half-cycle calculations are given in Table 1 and Table 2 under the columns labeled *Half cycle* and are shown to be less than the multipliers given under the column labeled *Exact*. The half-cycle equation is as follows:

$$I_{peak} = I_{ac\ peak} + I_{dc} = \sqrt{2} I_{ac\ rms} \left( 1 + e^{-\frac{2\pi\tau}{(X/R)}} \right) \tag{7}$$

where

$t$ = 0.5 cycles

The IEC calculating procedure for short-circuit currents includes the empirical formula shown in Equation (8) for estimating the absolute maximum peak current value, knowing the circuit fault point *X/R* ratio. This expression provides a rather close approximation to the exact peak current values and is conservative for circuit fault point *X/R* ratios greater than 3. Determining peak currents for circuit *X/R* ratio less than 3 is rarely necessary. Because most types of protective equipment short-circuit ratings are based on fault point *X/R* ratios greater than 3 (power factor lower than 31.6%), a current correction or multiplying factor is not needed. The peak current multipliers at one half-cycle are given in Table 1 and Table 2 under the columns labeled *IEC*. The form of Equation (7) should not be used for the peak current when applying

equipment because it is non-conservative. The equation is given here for reference only. The IEC equation is shown in Equation (8):

$$I_{peak} = \sqrt{2} I_{ac,rms} \left( 1.02 + 0.98 e^{-\frac{3}{(X/R)}} \right) \tag{8}$$

From the IEC Equation (8), the dc component would be as shown in Equation (9):

$$I_{dc} = \sqrt{2} I_{ac,rms} \left( 0.02 + 0.98 e^{-\frac{3}{(X/R)}} \right) \tag{9}$$

An alternate equation is available that provides a closer approximation to the exact peak currents than either the half cycle or IEC methods. The expression has two parts. First, a fictitious time $\tau$ is calculated from Equation (10) and then substituted into Equation (7) for $t$. For convenience, Equation (7) is listed below Equation (10).

$$\tau = 0.49 - 0.1 e^{-\frac{(X/R)}{3}} \tag{10}$$

$$I_{peak} = I_{ac\,peak} + I_{dc} = \sqrt{2} I_{ac,rms} \left( 1 + e^{-\frac{2\pi\tau}{(X/R)}} \right)$$

The peak current calculations provided by the combination of these two equations yields a very close approximation to the exact peak current and is conservative for most values of circuit *X/R* ratios greater than 0.81. The non-conservative errors for circuit *X/R* ratios around 10 are negligible. If a conservative multiplier is required for these circuit *X/R* ratios, then 0.0001 can be added to the peak current multiplier. The peak current multipliers for this alternate approach for the maximum half-cycle values are given in Table 1 under the columns labeled *Conservative approx*.

Equation (11), Equation (12), and Equation (13) are used for peak current factors in Table 1.

$$Half\text{-}cycle_{peak} = I_{ac\,peak} \left( 1 + e^{-\frac{\pi}{(X/R)}} \right) \tag{11}$$

$$IEC_{peak} = I_{ac\,peak} \left( 1.02 + 0.98 e^{-\frac{3}{(X/R)}} \right) \tag{12}$$

$$Conservative\ approx._{peak} = I_{ac\,peak} \left( 1 + e^{-\frac{2\pi\tau}{(X/R)}} \right) \tag{13}$$

where

$$\tau = 0.49 - 0.1 e^{-\frac{(X/R)}{3}} \tag{14}$$

Negative percent error occurs when the above equations predict a value less than the exact value for the first-cycle peak current. Therefore, the equations can be considered as non-conservative for any conditions that produce negative error.

A similar set of equations can be used for first-cycle rms current factors where:

$$I_{rms} = \sqrt{I_{ac,rms}^2 + I_{dc}^2} \quad IEC_{rms} = I_{ac\,rms}\sqrt{1+2\left(1.02+0.98e^{-\frac{3}{(X/R)}}\right)^2} \tag{15}$$

Recall the difficulty in determining the rms value of a non-periodic waveform. Equation (15) is valid only when $I_{dc}$ is constant. In short-circuit currents, the dc term is a decaying exponential and is not constant; it is a very common practice to evaluate this term at half-cycle after fault initiation even though this point in time does not necessarily correspond to the maximum peak value of the asymmetrical fault current.

These equations are given as follows and used in Table 2.

$$IEC_{rms} = I_{acrms}\sqrt{1+2\left(1.02+0.98e^{-\frac{3}{(X/R)}}\right)^2} \tag{16}$$

$$Half\ cycle_{rms} = I_{ac\,rms}\sqrt{1+2\left(e^{-\frac{\pi}{(X/R)}}\right)^2} \tag{17}$$

$$Conservative\ approx_{rms} = I_{ac\,rms}\sqrt{1+2e^{-\frac{4\pi\tau}{(X/R)}}} \tag{18}$$

where

$$\tau = 0.49 - 0.1e^{-\frac{(X/R)}{3}}$$

As with the first-cycle peak current, any of the above equations that produce negative percent errors can be considered non-conservative under the specified conditions. Equation (17) has been given here for reference because it has been used in other texts. Use of this equation is not recommended in those instances where the first-cycle rms current value obtained is to be used for equipment application because the current value obtained is non-conservative.

**Table 1—Differences in per-unit peak currents based on Equation (11), Equation (12), and Equation (13). One per unit equals ac peak.**

| Exact | | | | IEC Equation (11) | | Half-cycle Equation (12) | | Conservative approx. Equation (13) | |
|---|---|---|---|---|---|---|---|---|---|
| *X/R* | Time to peak (CY) | DC | Maximum peak | Maximum peak | Percent error | Maximum peak | Percent error | Maximum peak | Percent error |
| 0.5 | 0.3213 | 0.0078 | 1.0078 | 1.0224 | 1.45 | 1.0019 | −0.59 | 1.0061 | −0.16 |
| 1.0 | 0.3635 | 0.0694 | 1.0694 | 1.0688 | −0.06 | 1.0432 | −2.45 | 1.0722 | 0.26 |
| 1.5 | 0.3891 | 0.1571 | 1.1571 | 1.1526 | −0.39 | 1.1231 | −2.94 | 1.1656 | 0.73 |
| 2.0 | 0.3977 | 0.2418 | 1.2418 | 1.2387 | −0.25 | 1.2079 | −2.73 | 1.2521 | 0.83 |
| 2.5 | 0.4063 | 0.3157 | 1.3157 | 1.3152 | −0.04 | 1.2846 | −2.36 | 1.3255 | 0.75 |
| 3.0 | 0.4282 | 0.3786 | 1.3786 | 1.3805 | 0.14 | 1.3509 | −2.01 | 1.3870 | 0.61 |
| 3.5 | 0.4357 | 0.4319 | 1.4319 | 1.4359 | 0.28 | 1.4075 | −1.70 | 1.4388 | 0.48 |
| 4.0 | 0.4417 | 0.4774 | 1.4774 | 1.4829 | 0.37 | 1.4559 | −1.45 | 1.4827 | 0.36 |
| 6.0 | 0.4575 | 0.6057 | 1.6057 | 1.6144 | 0.54 | 1.5924 | −0.83 | 1.6072 | 0.09 |
| 8.0 | 0.4665 | 0.6842 | 1.6842 | 1.6935 | 0.56 | 1.6752 | −0.53 | 1.6843 | 0.01 |
| 10.0 | 0.4735 | 0.7368 | 1.7368 | 1.7460 | 0.53 | 1.7304 | −0.37 | 1.7367 | −0.01 |
| 14.0 | 0.4795 | 0.8027 | 1.8027 | 1.8110 | 0.46 | 1.7990 | −0.20 | 1.8029 | 0.01 |
| 20.0 | 0.4852 | 0.8566 | 1.8566 | 1.8635 | 0.37 | 1.8546 | −0.11 | 1.8574 | 0.04 |
| 25.0 | 0.4880 | 0.8832 | 1.8832 | 1.8892 | 0.32 | 1.8819 | −0.07 | 1.8841 | 0.05 |
| 30.0 | 0.4899 | 0.9015 | 1.9015 | 1.9067 | 0.27 | 1.9006 | −0.05 | 1.9025 | 0.05 |
| 40.0 | 0.4923 | 0.9250 | 1.9250 | 1.9292 | 0.22 | 1.9245 | −0.03 | 1.9259 | 0.05 |
| 50.0 | 0.4938 | 0.9395 | 1.9395 | 1.9429 | 0.18 | 1.9391 | −0.02 | 1.9403 | 0.04 |
| 75.0 | 0.4958 | 0.9591 | 1.9591 | 1.9616 | 0.12 | 1.9590 | −0.01 | 1.9598 | 0.03 |
| 100.0 | 0.4969 | 0.9692 | 1.9692 | 1.9710 | 0.09 | 1.9691 | −0.00 | 1.9697 | 0.03 |
| 250.0 | 0.4987 | 0.9875 | 1.9875 | 1.9883 | 0.04 | 1.9875 | −0.00 | 1.9878 | 0.01 |
| 500.0 | 0.4994 | 0.9937 | 1.9937 | 1.9941 | 0.02 | 1.9937 | −0.00 | 1.9939 | 0.01 |
| 1000. | 0.4997 | 0.9969 | 1.9969 | 1.9971 | 0.01 | 1.9969 | −0.00 | 1.9969 | 0.00 |

**Table 2—Per-unit rms currents at peak ac current based on Equation (16), Equation (17), and Equation (18). One per unit equals ac rms**

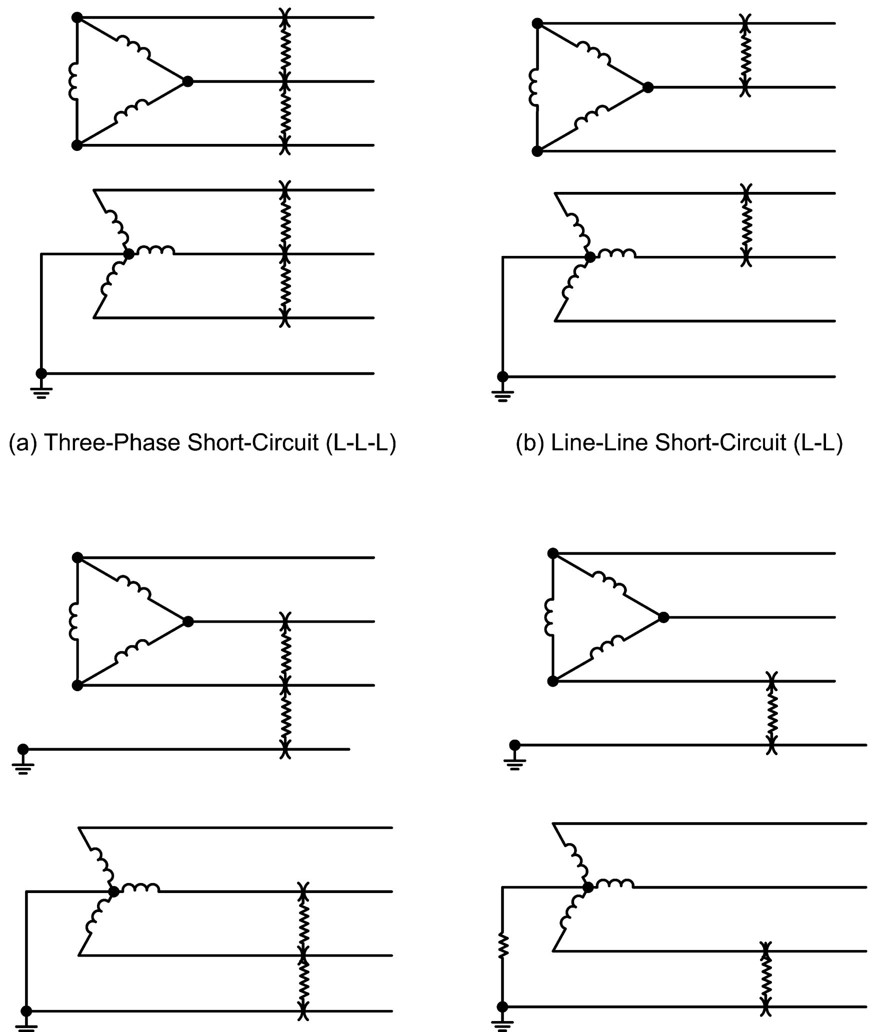
| Exact | | | | IEC Equation (16) | | Half-cycle Equation (17) | | Conservative approx. Equation (18) | |
|---|---|---|---|---|---|---|---|---|---|
| *X/R* | Time to peak (CY) | DC | Maximum rms | Maximum rms | Percent error | Maximum rms | Percent error | Maximum rms | Percent error |
| 0.5 | 0.3213 | 0.0110 | 1.0001 | 1.0005 | 0.04 | 1.0000 | −0.01 | 1.0000 | −0.00 |
| 1.0 | 0.3635 | 0.0981 | 1.0048 | 1.0047 | −0.01 | 1.0019 | −0.29 | 1.0052 | 0.04 |
| 1.5 | 0.3891 | 0.2222 | 1.0244 | 1.0230 | −0.13 | 1.0151 | −0.91 | 1.0270 | 0.26 |
| 2.0 | 0.3977 | 0.3419 | 1.0568 | 1.0554 | −0.13 | 1.0423 | −1.37 | 1.0616 | 0.45 |
| 2.5 | 0.4063 | 0.4464 | 1.0951 | 1.0948 | −0.03 | 1.0780 | −1.57 | 1.1009 | 0.53 |
| 3.0 | 0.4282 | 0.5354 | 1.1343 | 1.1356 | 0.11 | 1.1164 | −1.58 | 1.1400 | 0.50 |
| 3.5 | 0.4357 | 0.6108 | 1.1718 | 1.1747 | 0.25 | 1.1542 | −1.50 | 1.1769 | 0.43 |
| 4.0 | 0.4417 | 0.6751 | 1.2066 | 1.2110 | 0.36 | 1.1899 | −1.38 | 1.2108 | 0.35 |
| 6.0 | 0.4575 | 0.8566 | 1.3167 | 1.3248 | 0.61 | 1.3045 | −0.93 | 1.3181 | 0.10 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 8.0 | 0.4665 | 0.9676 | 1.3915 | 1.4007 | 0.66 | 1.3827 | −0.63 | 1.3916 | 0.01 |
| 10.0 | 0.4735 | 1.0420 | 1.4442 | 1.4536 | 0.65 | 1.4377 | −0.45 | 1.4441 | −0.01 |
| 14.0 | 0.4795 | 1.1352 | 1.5128 | 1.5216 | 0.58 | 1.5089 | −0.26 | 1.5131 | 0.02 |
| 20.0 | 0.4852 | 1.2114 | 1.5709 | 1.5784 | 0.48 | 1.5687 | −0.14 | 1.5717 | 0.05 |
| 25.0 | 0.4880 | 1.2491 | 1.6001 | 1.6066 | 0.41 | 1.5986 | −0.09 | 1.6011 | 0.06 |
| 30.0 | 0.4899 | 1.2750 | 1.6203 | 1.6261 | 0.36 | 1.6193 | −0.07 | 1.6214 | 0.06 |
| 40.0 | 0.4923 | 1.3082 | 1.6466 | 1.6513 | 0.28 | 1.6460 | −0.04 | 1.6476 | 0.06 |
| 50.0 | 0.4938 | 1.3286 | 1.6629 | 1.6668 | 0.24 | 1.6625 | −0.02 | 1.6638 | 0.06 |
| 75.0 | 0.4958 | 1.3564 | 1.6852 | 1.6880 | 0.16 | 1.6850 | −0.01 | 1.6859 | 0.04 |
| 100.0 | 0.4969 | 1.3706 | 1.6966 | 1.6988 | 0.13 | 1.6965 | −0.01 | 1.6972 | 0.03 |
| 250.0 | 0.4987 | 1.3966 | 1.7177 | 1.7186 | 0.05 | 1.7177 | −0.00 | 1.7179 | 0.02 |
| 500.0 | 0.4994 | 1.4054 | 1.7248 | 1.7253 | 0.03 | 1.7248 | −0.00 | 1.7250 | 0.01 |
| 1000. | 0.4997 | 1.4099 | 1.7285 | 1.7287 | 0.01 | 1.7284 | −0.00 | 1.7285 | 0.00 |

## 5.11 Types of faults

In a three-phase power system, the type of faults that can occur are classified by the combination of conductors or buses that are faulted together. In addition, faults may be classified as either bolted faults or faults that occur through some impedance, such as an arc. Each of the basic types of faults will be described and shown in Figure 10, but it should be noted that in a majority of cases, the fault current calculation required for the selection of interrupting and withstand current capabilities of equipment is the three-phase bolted fault with zero impedance. Other fault impedances may be needed for other fault calculations for protection and arc flash tasks.

A three-phase bolted fault describes the condition where the three conductors are physically held together with zero impedance between them, just as if they were bolted together. For a balanced symmetrical system, the fault current magnitude is balanced equally within the three phases. While this type of fault does not occur frequently, its results are used for protective device selection, because this fault type generally yields the maximum short-circuit current values. Figure 10(a) provides a graphical representation of a bolted three-phase fault.



(a) Three-Phase Short-Circuit (L-L-L) (b) Line-Line Short-Circuit (L-L)

(c) Double Line-Ground Short-Circuit (L-L-G) (d) Line-Ground Short-Circuit (L-G)

**Figure 10—Designation of short-circuit categories**

Bolted line-to-line faults, Figure 10(b), are more common than three-phase faults and have fault currents that are approximately 87% of the three-phase bolted fault current. This type of fault is not balanced within the three phases and its fault current is seldom calculated for equipment ratings because it does not provide the maximum fault current magnitude. The line-to-line current can be calculated by multiplying the three-phase value by 0.866, when the impedance $Z_1 = Z_2$. Special symmetrical component calculating techniques are not required for this condition.

Line-to-line-to-ground faults, Figure 10(c), are typically line-to-ground faults that have escalated to include a second-phase conductor. This is an unbalanced fault. The magnitudes of double line-to-ground fault currents are usually greater than those of line-to-line faults, but are less than those of three-phase faults. Calculation of double line-to-ground fault currents requires the use of symmetrical components analysis. The impedance of the ground return path will affect the result, and should be obtained if possible.

Line-to-ground faults, Figure 10(d), are the most common type of faults and are usually the least disturbing to the system. The current in the faulted phase can range from near zero to a value slightly greater than the bolted three-phase fault current. The line-to-ground fault current magnitude is determined by the system grounding method and the impedance of the ground return path of the fault current. Calculation of the exact

line-to-ground fault current magnitudes requires the special calculating techniques of symmetrical components. However, close approximations can be made knowing the method of system grounding used (refer to IEEE P3003.1 or IEEE Std 142™ for additional information regarding system grounding methods). On ungrounded distribution systems, the line-to-ground fault currents are near zero. Line-to-ground fault current magnitudes in distribution systems with resistance grounded system neutrals can be estimated by dividing the system line-to-neutral voltage by the total value of the system ground-to-neutral resistance. Line-to-ground fault current magnitudes in distribution systems with a solidly grounded system will be approximately equal to the three-phase fault current magnitudes. Determining line-to-ground fault currents on long cable runs or transmission lines will require detailed ground return path impedance data and detailed calculation techniques.

## 5.12 Arc resistance

Fault arc resistance is a highly variable quantity and changes non-linearly with the current during a cycle and on a cycle-by-cycle basis. The higher the current, the greater the ionized area, and the lower the resistance of the arc. The voltage across the arc, although not fixed, is more constant than the resistance. Arcing fault current magnitudes on low-voltage systems (< 1000 V) are more affected by fault resistance than are higher voltage systems, and the fault current can be considerably smaller in magnitude than the bolted fault current values, as shown in Table 3. On higher-voltage networks (> 1000 V), the fault arc resistance (and therefore the arc voltage) often is very low and approaches zero (bolted fault). Arcing faults in higher voltage systems have been shown to have a ground fault current ranging from 0% to 100% of the bolted-fault current depending on the system voltage and the type of fault involved. The higher the possible fault current magnitude, the lower the fault resistance will be.

The environment in which the fault takes place has an effect on the fault resistance and its being sustained. An arcing fault in a confined area is easily perpetuated due to the concentration of ionized gases allowing easy current flow. An arc occurring on open conductors is elongated due to heat convection, thereby allowing cooling of ionized gas and the arc may extinguish itself.

**Table 3—Approximate minimum value of arcing fault current in per unit of three-phase bolted fault**

| Type of arcing fault | System voltage | |
|---|---|---|
| | 480Y/277V | 208Y/120V |
| Three-phase | 89% | 12% |
| Line-to-line | 74% | 2% |
| Line-to-ground | 38% | 1% |

Arcing fault currents are known to be very erratic in nature and do not provide a constant resistance during any one cycle. Over several cycles, the arc ignites due to uncooled ionized gases, almost extinguishes, then fully ignites again with varying current. There is not an exact equation available to determine arcing fault resistance. However, the reference works of Alm [B1], Brown [B8], and Strom [B61] provide an approximation [Equation (19), Equation (20), and Equation (21)].

$$\frac{V}{\text{cm}} = 50\left(\frac{P}{I^2}\right)^{1/6} \tag{19}$$

or in terms of resistance:

$$\frac{R}{\text{cm}} = 50(P)^{\frac{1}{6}}(I)^{\frac{3}{4}} \tag{20}$$

where

$V$ is voltage, volts

$R$ is resistance in ohms

cm is arc length, centimeters

$P$ is pressure in atmosphere (1 atm = 14.696 PSIA)

$I$ is current in kiloamperes (kA)

Note that the equation parameters contain currents that make the application of Ohm's law non-linear and more complex. It should also be noted that the equations provide voltage and resistance per centimeter. Therefore, the total arc voltage or resistance can be determined by multiplying Equation (19) and Equation (20) by the total arc length.

The instantaneous arc resistance at current peak can be calculated using Equation (21).

$$R = 11.6 \times \ell \times \frac{1.1}{I_x} \tag{21}$$

where

$\ell$ = length of arc in centimeters

$I_x$ = peak current in kiloamperes (kA)

In the calculation of fault current magnitudes, when maximum ampere conditions for equipment evaluation is the concern, arcing fault impedance or arc resistance is considered zero. For other calculation purposes, some assessment of fault impedance may be necessary. Note that in practice, arc length varies substantially over time, even if the end points of the arc are fixed.

# 6. General short-circuit calculation method

## 6.1 Introduction

In order to calculate, with a reasonable degree of accuracy, the short-circuit current that can be expected to flow in a system, it is necessary to find an equivalent circuit for each system element that will adequately represent its performance under short-circuit conditions. Without the use of simplifying techniques, one is often faced with the necessity of solving complex differential equations to determine the short-circuit current.

In this clause, various calculating techniques will be discussed with particular emphasis placed on simplifying techniques and manipulations that will provide acceptable results using system conditions that are recognized and accepted.

## 6.2 Fundamental principles

A basic ac power circuit containing resistance ($R$), inductance ($L$), and capacitance ($C$) is shown in Figure 11. For completeness, the series capacitor is shown, although its use in power circuits is limited. The general expression relating the instantaneous current response ($i$) and the instantaneous exciting source voltage ($e$) in such a circuit will take the form (see IEEE Std 141™-1993 [B31]):

$$e = L\frac{di}{dt} + Ri + \frac{1}{C}\int i\,dt + e_0 \tag{22}$$

$$e = L\frac{d^2Q}{dt^2} + R\frac{dQ}{dt} + \frac{Q}{C} + e_0 \tag{23}$$

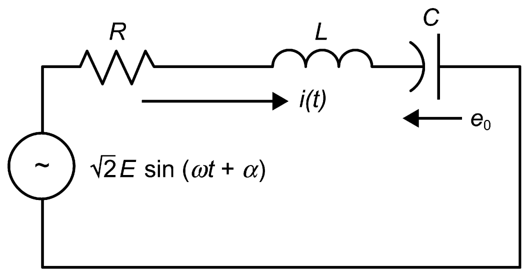



**Figure 11—Series RLC circuit**

The expression for the response (for current) involves the solution of a differential equation as shown in many electrical engineering textbooks. However, industrial and commercial power system networks contain many branches composed of series and parallel combinations of resistance, inductance, and capacitance, which add greatly to the complexity of using the fundamental expression for circuit analysis. In addition, the calculation of system short-circuit currents is further complicated by the varying fluxes (driving voltages) in equipment along with the prefault and post-fault steady-state behavior. In calculating short-circuit currents, it is expedient to use techniques that will simplify the general circuit equation as much as possible while still providing valid results that are sufficiently accurate for their intended purpose.

Each of the network theorems and calculating techniques described in this recommended practice are valid for a specific calculation. They place various constraints on the general circuit equation in order to achieve calculation simplicity. It must be emphasized that these constraints must have some basis in order to obtain valid results. Fortunately, it is often possible to introduce appropriate corrections artificially when restraints are violated by system conditions. However, in certain cases it may be necessary to use the formal differential equations to obtain a valid solution.

The following constraints are common to all of the techniques that will be discussed, with the exception of the Fourier representation:

a) The ac source frequency must be constant. In power system short-circuit analysis, it is reasonable to assume constant system frequency for the fault duration except for very rare and special cases.

b) The impedance coefficients *R, L,* and *C* must be constant (saturated values). Again, for the majority of short-circuit calculations this restraint causes no difficulty since the maximum fault current is of concern and the fault resistance is taken to be zero when the equipment rating is evaluated. The following, however, are examples of system conditions where the restraint will be violated. When an arc becomes a series component of the circuit impedance, the *R* that it represents is not constant. For example, at a current of 1 A, it is likely to be 100 Ohm, yet at a current of 1000 A it would very likely be about 0.1 Ohm (see IEEE Std 141™-1993 [B31]). During each half-cycle of current flow, the arc resistance would traverse this range. It is difficult to determine a proper resistance value to insert in the 60 Hz network. A correct value of *R* does not compensate for the violation of the constraint that demands that *R* be a constant. The variation in *R* lessens the impedance to high-magnitude current, which results in a wave shape of current that is more peaked than a sine wave. The current now contains harmonic terms. Because they result from a violation of analytical restraints, they will not appear in the calculated results. Their character and magnitude must be determined by other means and the result artificially introduced into the solution for fault current.

A similar type of non-linearity may be encountered in electromagnetic elements in that iron plays a part in setting the value of $L$. If the ferric parts are subject to large excursions of magnetic density, the value of $L$ may be found to drop substantially when the flux density is driven into the saturation region. The effect of this restraint violation will, like the case of variable $R$, result in the appearance of harmonic components in the true circuit current.

c) The driving voltage and its phase angle are assumed to be constant. In reality, however, a machine's internal driving voltage varies with machine loading and time. During a fault, the machine's magnetic energy or internal voltage is reduced faster than it can be replaced by energy supplied by the machine's field. The rate of decay differs for each source. In addition, the angles between machines begin to change as some accelerate and others slow down.

The resistance and reactance of machines are fixed values based on the physical design of the equipment. Solving a system with many varying driving voltage sources becomes cumbersome. The same current can be determined by holding the voltage constant and varying the machine impedance. This interchange helps to simplify the mathematics. The value of the impedance that must be used in these calculations depends on the basis of rating for the protective device or equipment under consideration. Different types of protective devices or equipment require different machine impedances to determine the fault current duty. Equipment evaluated on first-cycle criteria would use a lower machine impedance, and hence a higher current, than equipment evaluated on an interrupting-time basis.

d) The fault current source must be sinusoidal. Most voltages and currents used for transmission and utilization of electric power are generated by the uniform rotation of an armature in a magnetic field; the resulting steady-state voltage is periodic and has a waveform that is nearly a pure sine wave or one that can be resolved into a series of sine waves.

The vector impedance analysis recognizes only the steady-state sine wave electrical quantities and does not include the effects of abrupt switching. Fortunately, the effects of switching transients can be analyzed separately and added, provided the network is linear. An independent solution can be obtained from a solution of the formal differential equations of the form of Equation (22) (see IEEE Std 141-1993 [B31]).

In the case of a totally resistive ($R$) network, (Figure 12), the closure of the switch $SW$ causes the current to immediately assume the value that would exist in steady-state. No transient will be produced.

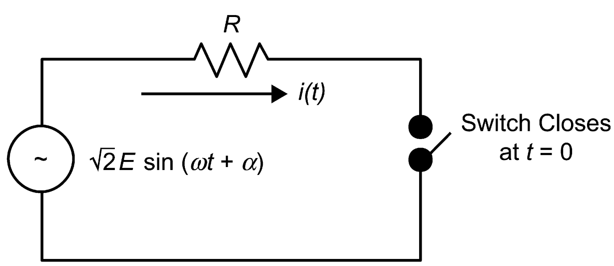



**Figure 12 —Switching a resistive circuit**

In the case of inductance ($L$), (Figure 13), an understanding of the switching transient can be best acquired using the expression shown in Equation (24).

$$e = L\frac{di}{dt} \qquad (24)$$

Or expressed in terms of $i$:

$$\frac{di}{dt} = \frac{e}{L} \tag{25}$$

This expression tells us that the application of a driving voltage to an inductance will create a time-rate-of-change in the resultant current flow. The current waveform, one example of which is shown in Figure 13, may be fully offset or not offset at all, depending on the point on the applied voltage wave at which the switch is closed. The waveform in Figure 13 assumes a voltage angle (at switch closing) of 180°, so a full negative offset will be produced.

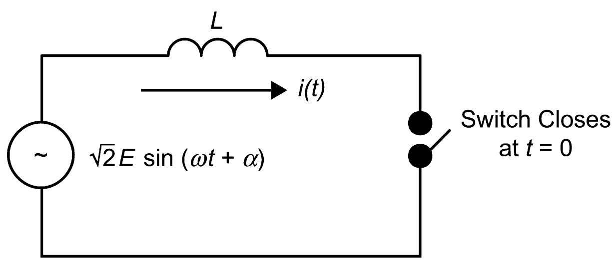



**Figure 13—Switching an inductive circuit**

At half-cycle in Figure 13, the steady-state current curve waveform begins with a maximum negative dc offset. The offset is negative because the voltage at half-cycle is *zero going negative,* meaning that the instantaneous value is zero at half-cycle, but the next value will be negative. At this same instant (half-cycle), the 90° lagging current through the inductor will be at a positive peak. Because the switch has been open prior to this instant, the inductor current must be zero at the instant the switch closes. Because the steady-state inductor current will be at its positive peak value at half-cycle, a constant current equal to the negative of this peak value must be produced starting at half-cycle such that the sum of the steady-state waveform and the constant is zero at half-cycle. In general, the transient that is produced when the switch is closed will take the form of a dc current component whose value may be anything between zero and the steady-state crest value (either positive or negative), depending on the angle of closing.

If the circuit contained no resistance, as depicted in Figure 13, the constant current would continue forever and the total waveform (the sum of this constant value and the sinusoidal steady-state current) would remain in the offset form. The presence of resistance causes the constant (often called *dc*) component to be dissipated exponentially. The complete expression for the current would take the form shown in Equation (26):

$$i = -\frac{\sqrt{2}E}{Z}\sin(\alpha-\varphi)e^{-\frac{\omega tR}{X}} + \frac{\sqrt{2}E}{Z}\sin(\omega t+\alpha-\varphi) \tag{26}$$

In Equation (26), the first part of the expression for the current has a constant term modified by a decaying exponential term (often called a *decaying dc term*). The second part of the equation is a steady-state sinusoidal term. To help distinguish these two terms, $\sqrt{2}\,E/Z$ will be identified as $i_{dc}$ in the first term and $\sqrt{2}I_{ac,\mathrm{rms}}$ in the second term. Note that at time $t = 0$ (the instant of fault initiation), these two terms are equal.

$$i = -i_{dc}\sin(\alpha-\varphi)e^{-\frac{\omega tR}{X}} + \sqrt{2}I_{ac,rms}\sin(\omega t+\alpha-\varphi) \tag{27}$$

where

$$f = tan^{-1}(\omega L/R) = tan^{-1}\left(X/R\right)$$

$$X = \omega L$$

$$Z = \left(R^2 + X^2\right)^{1/2}$$

If time $t$ is expressed in cycles, Equation (27) becomes:

$$i = -i_{dc} \sin(\alpha - \varphi) e^{-\frac{2\pi tR}{X}} + \sqrt{2} I_{ac,rms} \sin(2\pi t + \alpha - \varphi) \tag{28}$$

The presence of dc current components may introduce unique problems in providing selectivity in relay coordination between some types of overcurrent devices. It is particularly important to keep in mind that these transitory dc currents are not disclosed by the steady-state circuit solution often used in short-circuit fault calculations, but must be introduced artificially by the analyst, or by established rules and guidelines. A detailed differential equation model of the entire network, including machines using a dynamic flux model, would be required to obtain the transient currents.

It is common practice that the analyst considers the switching transient to occur only once during one excursion of short-circuit current flow. An examination of representative oscillograms of short-circuit currents will often display repeated instances of momentary current interruptions. At times, an entire half-cycle of current will be missing. In other cases, especially in low-voltage circuits, there may be present a whole series of chops and jumps in the current pattern. A switching interrupter, especially when switching a capacitor circuit, may be observed to restrike two, or perhaps three times before complete interruption is achieved. The restrike generally occurs when the potential difference across the switching contacts is high. It is entirely possible that switching transients, both simple dc and ac transitory oscillations, may be created in the circuit current a number of times during a single incident of short-circuit current flow. The analyst must remain mindful of possible trouble.

## 6.3 Short-circuit calculation procedure

The procedure for calculating short-circuit currents in industrial and commercial power systems can be described in five basic steps. With the help of an advanced computer software, steps c) to f) below are conducted automatically by the program.

a) Prepare a system one-line diagram showing all elements to be included in the analysis. The diagram should provide significant details to allow the user to identify the system nodes (buses) that will be considered in the short-circuit analysis. Transformers should be drawn with a transformer symbol, motors with a motor symbol, and so on. Depending on the complexities of the system drawing, the amount of equipment detail shown will vary. However, too much data will make it difficult to locate any item of concern. A separate equipment list can be used to reduce the data placed on the one-line diagram.

   When the single line is drawn in many of the available software analysis tools, this equipment list is automatically created as part of the model database. The ability to manipulate the representation of these data on the one-line diagram varies greatly between software vendors.

b) Prepare an impedance diagram showing the system impedances. Most engineers show impedance in per unit on a common MVA base. However, ohms can be used if the voltage for each bus is also given. The one-line diagram may be used together with the equipment list identifying the impedance data for the various components shown on the one-line diagram. Many computer programs allow the raw data to be used, thus eliminating the need for the impedance diagram. However, the impedance diagram must be considered when doing manual spot-checks of the software calculations. With manual calculations it is normal to show impedance in ohms.

c) Develop an equivalent circuit of the "outside world." This circuit represents the part of the system for which short-circuit calculations are not required, but its effect on the total fault current is

important and must be included. In the analysis of industrial and commercial power systems, the utility system is often represented as an equivalent circuit.

In representing multiple utility connections by multiple Thevenin equivalent circuits, it is essential to ensure that these are truly independent. If any utility connection points are interconnected, they cannot be represented by two Thevenin equivalent sources. This issue is discussed as *network diakoptics* (Happ [B16]). If the multiple utilities can be reduced to one common bus, then a single Thevenin equivalent can be derived and used in the industrial system model.

d) Calculate the symmetrical short-circuit current at the buses of concern. This is normally done by a computer program for large-scale systems. Hand calculation can also be done for small system, or as a spot check on computer calculations.

e) For ANSI short-circuit current calculations, apply appropriate multiplication factors to symmetrical short-circuit currents, as required to reflect the asymmetry of the short-circuit current. First-cycle and interrupting-time calculations may need multipliers if they are used for equipment evaluation, while steady-state (or 30 cycle) calculations used mainly for time-delay relay settings may not.

f) Compare the calculated short-circuit duties to the ratings of existing equipment or use the short-circuit duties to select equipment ratings.

## 6.4 One-line diagram

### 6.4.1 Introduction

When preparing the data for short-circuit studies, the first step is to develop a one-line diagram of the electrical system. In a balanced three-phase system, the circuit impedance for each phase is the same as for the other two phases. This symmetrical property is taken advantage of by drawing the electrical system as a single-phase drawing. This drawing is referred to as a *one-line*. Standard symbols from IEEE Std 315™-1975 or IEC 60617 are used to represent electrical apparatus. Figure 14, Figure 15, and Figure 16 provide the more commonly used symbols. The drawing should include all sources of short-circuit current, (utilities, generators, synchronous motors, induction motors, condensers, etc.) and all significant circuit elements, (transformers, cables, circuit breakers, fuses, etc.).

In developing the one-line diagram, the engineer must decide how much detail should be represented. Too much data can make the drawing cluttered and hard to read. For example, transformers can be labeled with the voltage rating, tap, kVA, and impedance, or be limited to the kVA rating and the percent impedance.

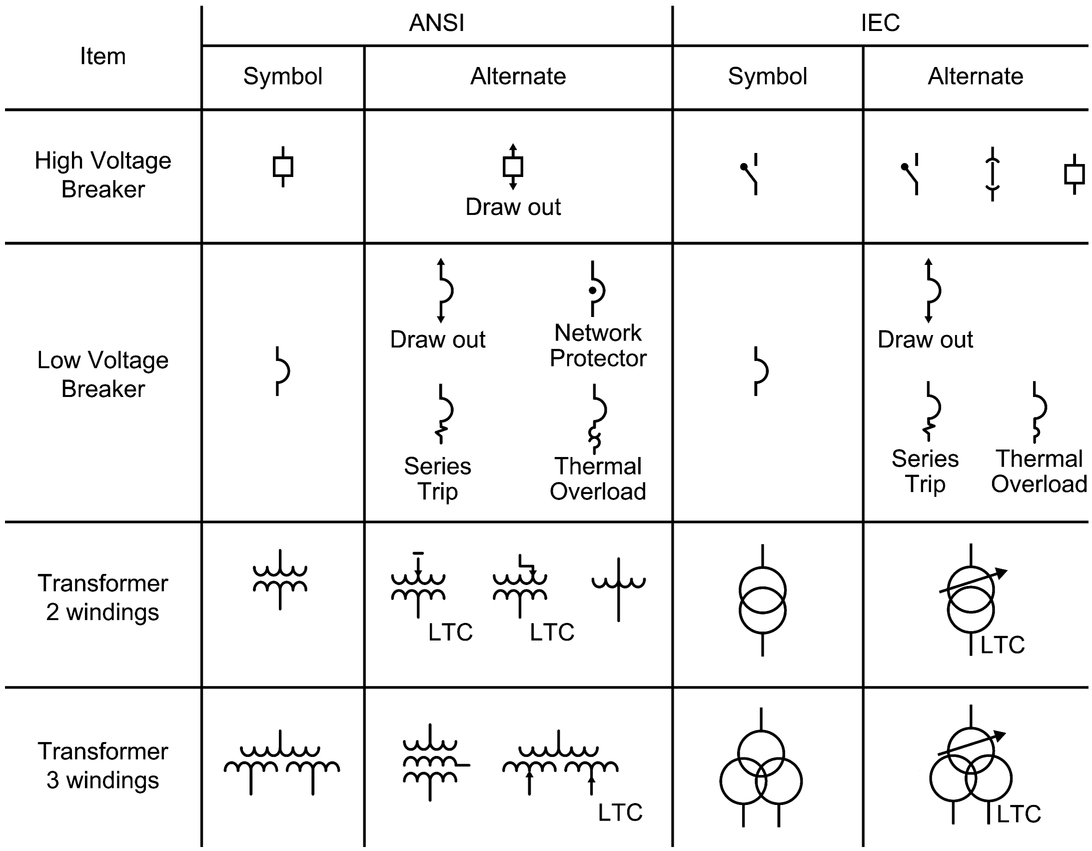



**Figure 14—Typical symbols used on one-line diagrams**

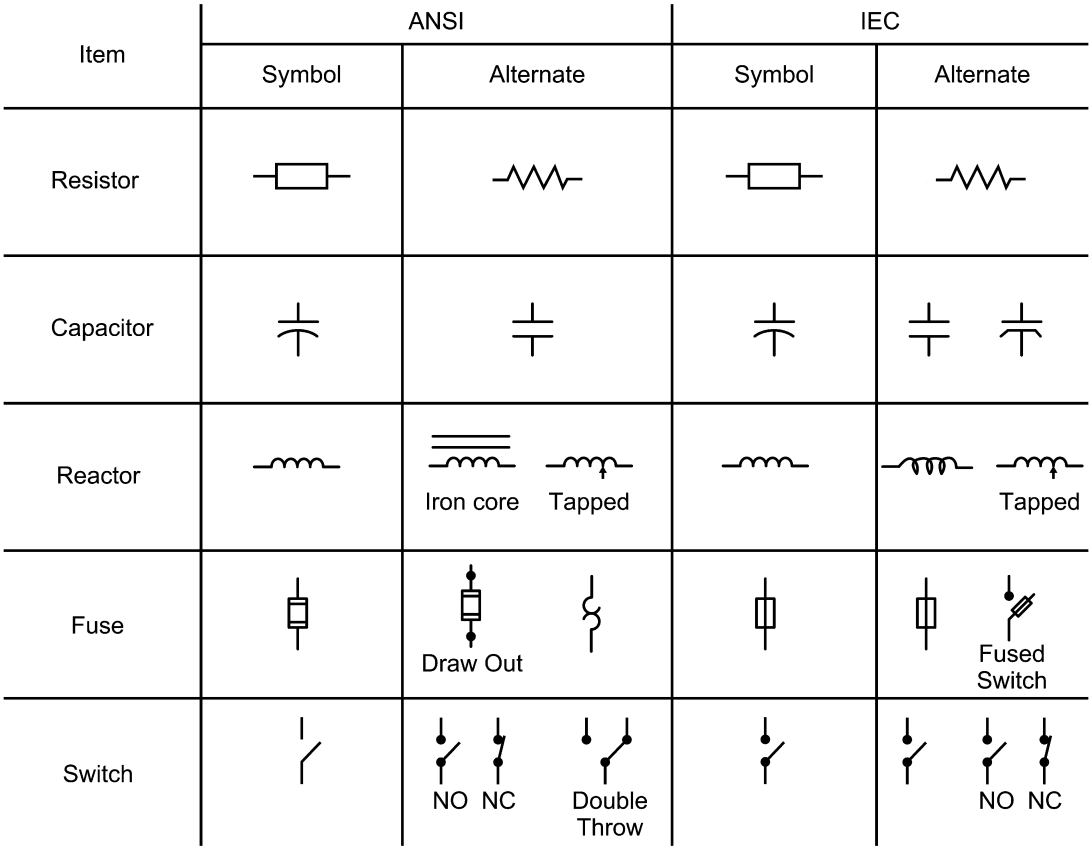



**Figure 15—Typical symbols used on one-line diagrams**

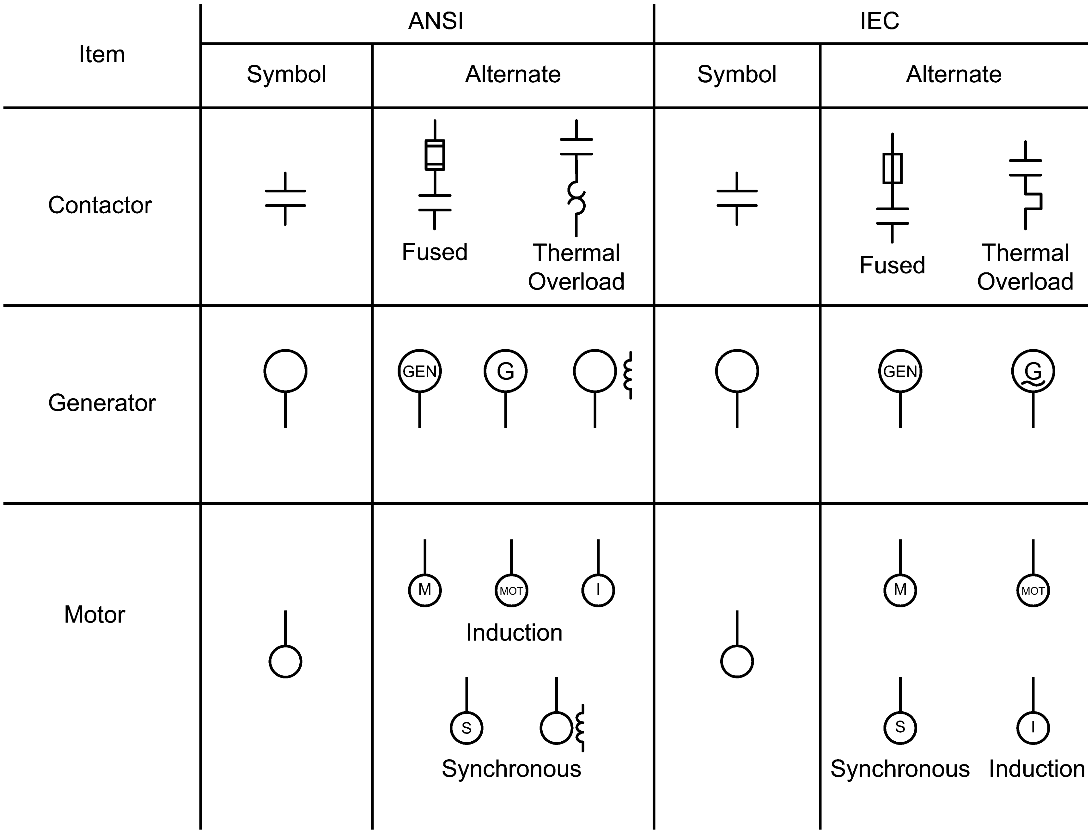



**Figure 16—Typical symbols used on one-line diagrams**

### 6.4.2 Single-phase equivalent circuit

The single-phase equivalent circuit is a tool for simplifying the analysis of balanced three-phase circuits, yet it is the solution method because the restraints are often disregarded (see Griffith [B11]). Its use is best understood by examining a three-phase diagram of a simple system and its single-phase equivalent, as shown in Figure 17. Also illustrated is the popular one-line diagram representation that is commonly used to describe the same three-phase system on drawings.

For a three-phase system known to have perfectly balanced symmetrical source excitation (voltage), loads, and shunt and series line impedances connected to all three phases (upper diagram), the neutral conductor (shown dashed), whether physically present or inserted for mathematical convenience, will carry no current. Under these conditions, the system can be accurately described by either of the two lower diagrams of Figure 17. The single-phase equivalent circuit is useful because the solution to the classical loop equations is much easier to obtain than for the more complicated three-phase network.

In the discussion that follows, it is assumed that there is no coupling between phases of the loads and power delivery equipment. Such coupling would not allow a "decoupled" analysis of one phase of the balanced circuit. Symmetrical component techniques (to be described later) can effectively decouple the three-phase circuits, assuming balanced (equal) coupling between phases, into zero, positive, and negative sequence equivalent circuits. Under balanced three-phase operating conditions, it can be shown that an analysis of the positive sequence equivalent circuit gives results that are identically equal to "a" phase values. For this reason, the concepts of *per phase, single-phase,* and *positive sequence* analysis are often used interchangeably. Note that this usage is not rigorously correct and can lead to confusion. The references should be consulted for a complete development of the equivalence (or lack thereof) of these various descriptive terms.

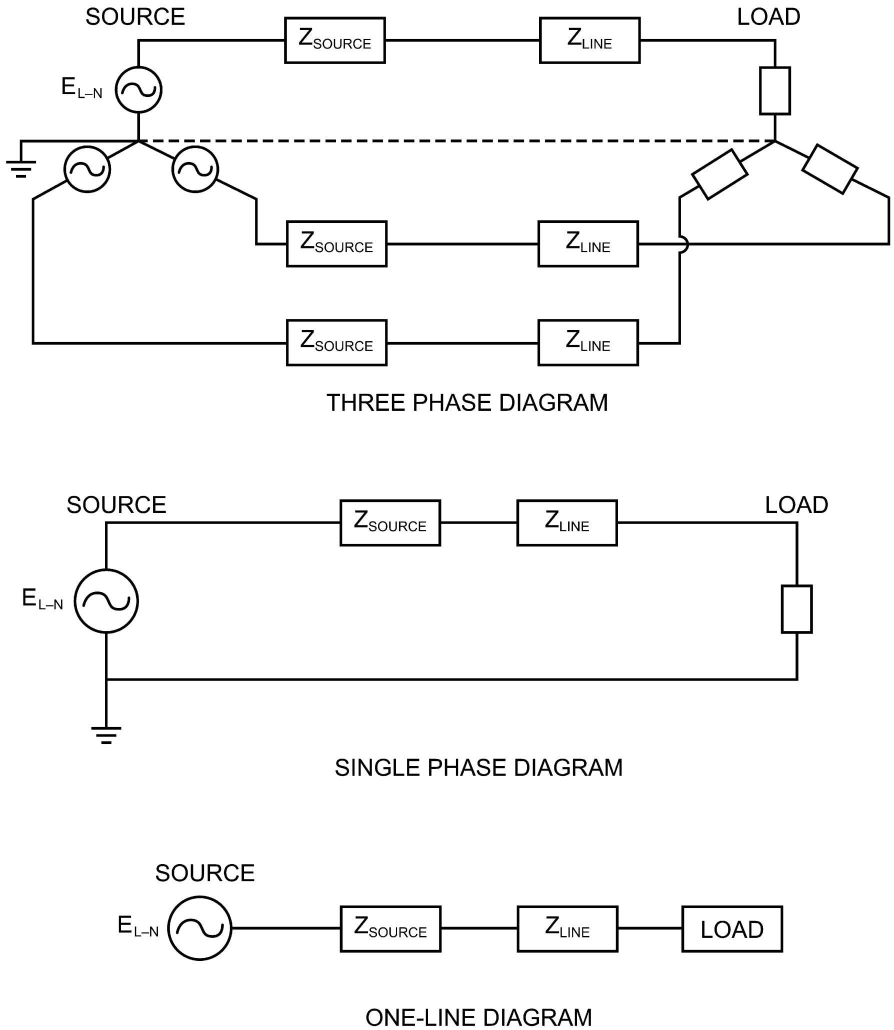



**Figure 17 —Electrical power diagrams**

In determining the complete short-circuit solution, the other two phases will have responses that are shifted by 120° and 240°, but are otherwise identical to that of the reference phase.

Anything that upsets the balance of the network renders the model invalid unless special calculating techniques are used. One instance for which this might occur is the line-to-ground fault shown in Figure 18. For this fault condition, the balance or symmetry of the circuit is destroyed. Neither the single-phase equivalent circuit nor the one-line diagram representation is valid. The single-phase and the one-line diagram representations would imply that the load has been disconnected. However, it continues to be energized by two-phase power as shown on the three-line diagram. So-called "single-phase operation" of three-phase equipment can cause serious damage to motors, for example, and may also result in unacceptable operating condition of certain load apparatus.

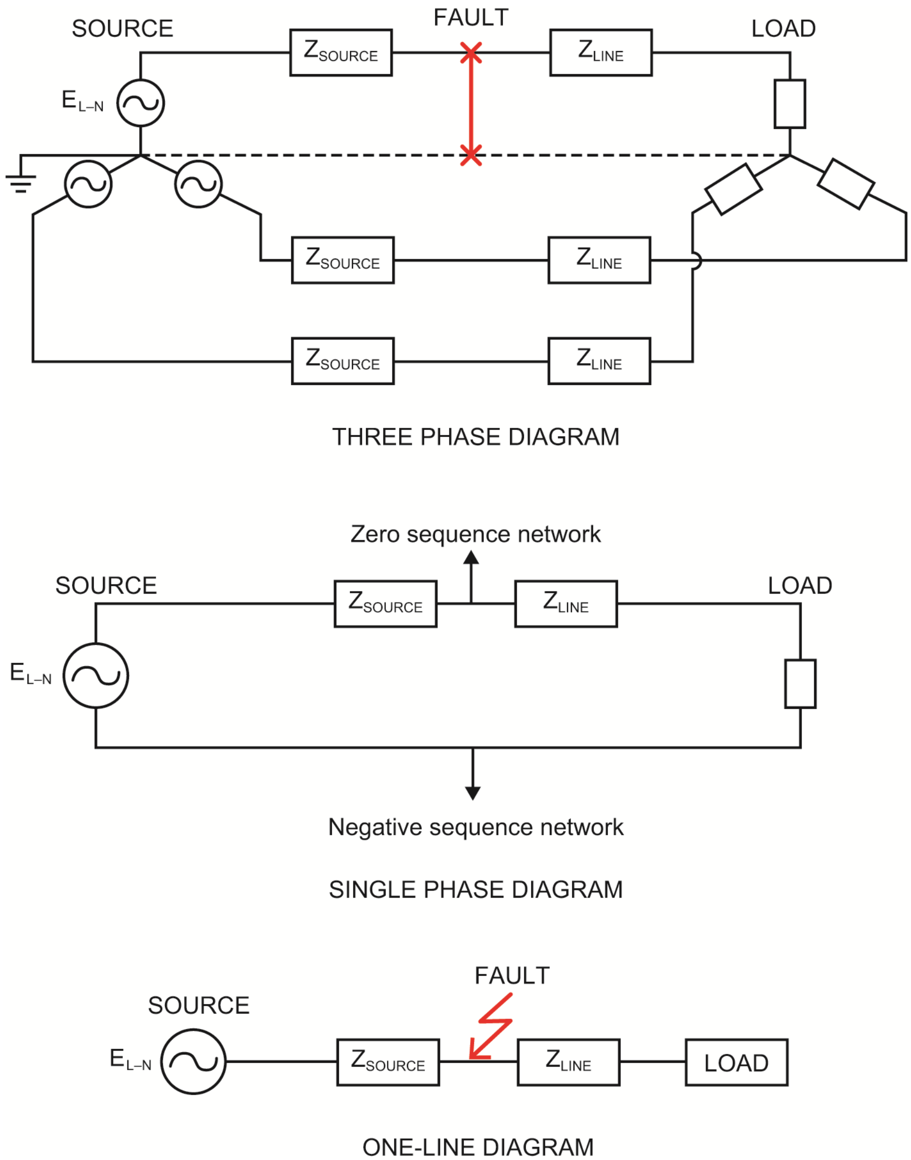



**Figure 18—Electrical power diagrams showing a line-to-ground fault**

### 6.4.3 Bus numbers

Some short-circuit analysis computer programs require the use of bus numbers identifying each individual bus on the one-line diagram to assist the engineer with the printed computer results. When bus numbers are required, each branch element of the electrical system must be between two distinct bus numbers. The one-line diagram is divided into circuit segments by assigning bus numbers as follows:

a) To a bus with three or more connections to it. These often are pieces of major equipment, such as switchgear buses, motor control center buses, substations, etc.

b) At utility connections and generator terminals.

c) At the terminals of motors when the cable connection to the motor is represented.

Sometimes it is convenient to place bus numbers at the junction point of two different branch elements, such as a cable connection to a transformer if the computer program can handle a large number of nodes. In other cases, the series per-unit impedances are added together and represented as a single element in the program. Care must be taken when combining series impedances to ensure that any impedance modifiers are applied to the correct elements. For example, in performing first-cycle and interrupting-time fault calculations, the motor impedances are modified. If the cable impedance is included in the motor impedance, the cable impedance should not be modified. Likewise, if transformer taps are to be changed, the cable should be represented as a single branch element between two buses.

### 6.4.4 Impedance diagrams

The companion document to the one-line diagram for short-circuit calculations is an impedance diagram. It is basically the same as the one-line diagram with each significant circuit element replaced by its respective impedance. Figure 20 is the impedance diagram for the electrical system shown in Figure 19. This drawing is a useful reference document. To reduce the quantity or size of drawings, only the one-line diagram is truly required, but it must be supplemented with tables providing the impedance data.

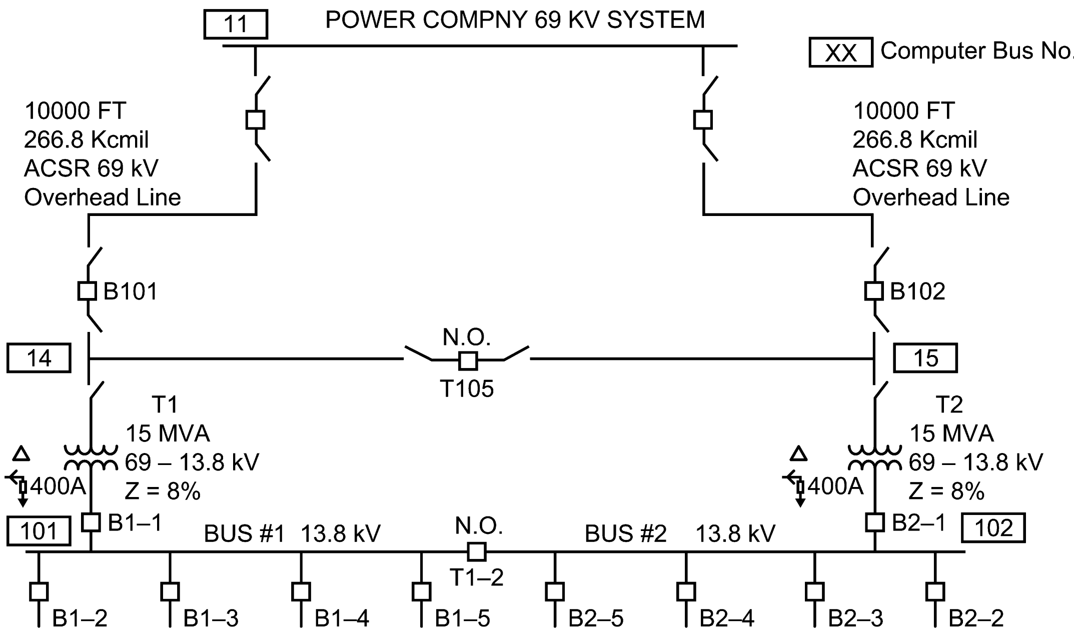



**Figure 19 —One-line diagram with bus numbers**

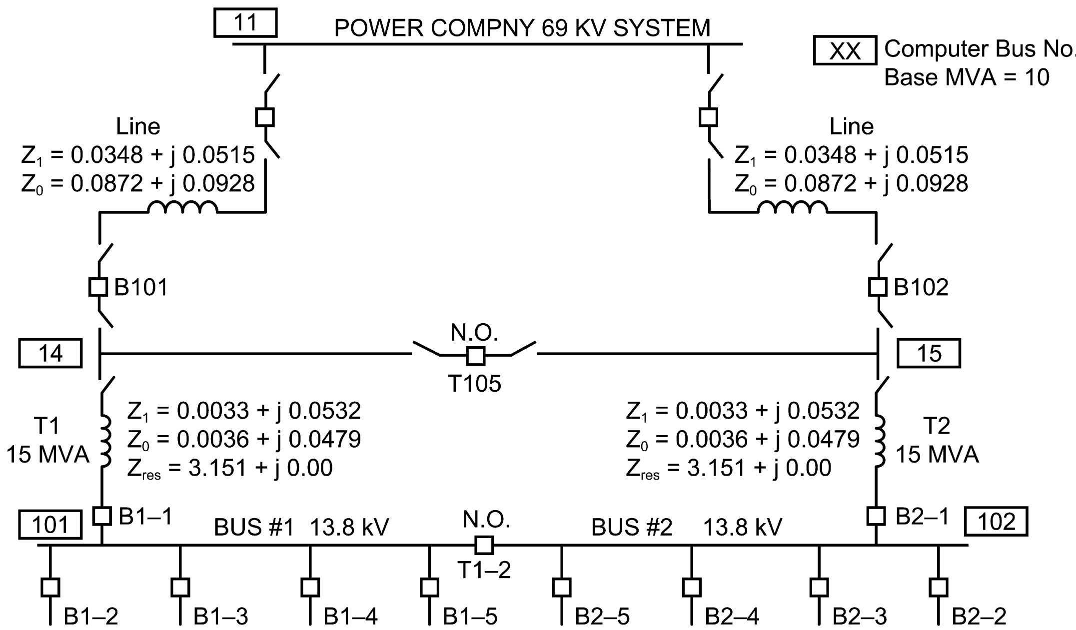



**Figure 20—Impedance one-line diagram**

### 6.4.5 Short-circuit flow diagrams

The short-circuit flow diagram is a one-line diagram showing direction and magnitude of short-circuit currents flowing in the connecting branches for a specific system short-circuit. These diagrams usually are an expanded view of one section of the one-line diagram to show the results of a short-circuit calculation. The flow of short-circuit currents in a branch is important to the protection engineer in determining settings for protective relays. Please refer to Clause 18 for illustration examples.

### 6.4.6 Protective device one-line diagrams

The protection device one-line diagram is a one-line diagram with current transformers, potential transformers, circuit breakers, fuses, and relay device function numbers or relay types shown. Details as to which circuit breaker the relay trips are sometimes given. Rather than placing all this detail on one system drawing, a protective device one-line is often provided for each substation or switchgear drawing. Sometimes these are expanded to *protection and control* drawings for a substation or a switchgear assembly.

## 6.5 Per-unit and ohmic manipulations

Short-circuit calculations are made to solve the equation $I = E/Z$. Obtaining values of the impedance $Z$ is a time-consuming effort when conducting a short-circuit analysis. The impedance $Z$, given on the equipment nameplate or furnished by the equipment manufacturer, may be identified either in per-unit or in ohmic values, but one or the other must be used consistently in any calculation. The same study results will ultimately be obtained for either ohmic or per-unit representation. Many engineers find the per-unit system easier to use because impedance changes due to transformer ratios are automatically taken into account. The per-unit system is a shorthand calculating technique where all equipment and circuit impedances are converted to a common base.

In using the ohmic system, all impedances must be referred to the appropriate voltage level by the square of the transformer turns ratio. With several levels of voltages, this can become an added bookkeeping task. In the per-unit system, changing impedance values because of transformer ratios is unnecessary. For example, using the same voltage base as the transformer primary and secondary voltages results in the transformer per-unit impedance being the same on both sides of the transformer. Equipment manufacturers usually state the impedance of electrical equipment in per unit on the kVA and voltage base of the equipment.

The per-unit impedances of machines (using the machine ratings as bases) of the same type (induction motor, synchronous motor, synchronous generator, etc.) are approximately the same for a broad range of machine sizes, while the ohmic values vary with the size of the machine. Knowing that the per-unit impedances fall within a fairly narrow band is advantageous when machine data must be estimated. Typical per-unit values are often used in preliminary designs or for small motors where individual test reports are not available.

In the per-unit system, there are many base quantities, including base apparent power (kVA or MVA), base volts (volts or kV), base impedance (ohms), and base current (amperes). Choosing any two automatically determines the other bases. The relationship between base, per unit, and actual quantities is as shown in Equation (29).

$$\text{per unit quantity} = \frac{\text{actual quantity}}{\text{base quantity}} \tag{29}$$

or rewritten

$$\text{actual quantity} = (\text{per unit quantity})(\text{base quantity}) \tag{30}$$

Normally, the base MVA is selected first and the most commonly used MVA bases are 10 MVA and 100 MVA, although any MVA or kVA base value may be used. Many utilities express impedance as *percent* impedance on a 100 MVA base, where percent impedance equals per-unit impedance times 100. The voltage at one level is chosen as the base voltage, which then determines the base voltage at the other levels using the primary and secondary operating voltage rating of the transformers. Rated transformer primary and secondary voltages are commonly used as the voltage bases.

For three-phase power systems, line-to-line voltage (usually expressed in kV) is used with three-phase kVA or MVA base. The following equations apply to three-phase systems. Equation (31) and Equation (32) convert the equipment and line data to a common base when the base voltages match the equipment voltages.

Converting ohms to per-unit impedance:

$$Z_{pu} = \frac{Z_{ohms} MVA_{base}}{kV_{LL\,Base}^{2}} \tag{31}$$

Converting per-unit ohms from an equipment MVA base to a common MVA base where base voltage equals equipment voltage:

$$Z_{Common\,Base} = \frac{Z_{Equipment\,Base} MVA_{Common\,Base}}{MVA_{Equipment\,Base}} \tag{32}$$

Converting per-unit ohms from an equipment voltage base to a common voltage base:

$$Z_{Common\ Base} = Z_{Equipment} \frac{kV^2_{LL\ Equipment}}{kV^2_{LL\ Common}} \tag{33}$$

Combining Equation (32) and Equation (33):

$$Z_{Common\ Base} = Z_{Equipment} \frac{(MVA_{Common\ Base})(kV^2_{LL\ Equipment\ Base})}{(MVA_{Eauipment\ Base})(kV^2_{LL\ Common\ Base})} \tag{34}$$

Having determined the MVA and voltage bases, the current and impedance bases for each voltage level can be determined. This provides a constant multiplier at each voltage level to obtain the current or per-unit impedance by the use of Equation (29) and Equation (30).

$$I_{Base\ (Amps)} = \frac{(MVA_{Base})1000}{\sqrt{3}kV_{LL}} \tag{35}$$

$$Z_{Base(Ohms)} = \frac{(kV^2_{LL})1000}{kVA} = \frac{kV^2_{LL}}{MVA} \tag{36}$$

Similar expressions can be used for a single-phase system with care exercised to use only quantities found in single-phase circuits. The current is the line current, the voltage is line-to-neutral voltage, and the base is the single-phase kVA or MVA. For example:

$$Z_{Common\ Base} = \frac{Z_{Equipment\ Base} MVA_{Common\ Base}}{MVA_{Equipment\ Base}} \tag{37}$$

Per-unit ohms on equipment voltage base to common voltage base:

$$Z_{Common\ Base} = Z_{Equipment} \frac{kV^2_{LN\ Equipment}}{kV^2_{LN\ Common}} \tag{38}$$

$$I_{Base} = \frac{(MVA_{Base})1000}{kV_{LN}} \tag{39}$$

## 6.6 Network theorem and calculation techniques

### 6.6.1 Introduction

The following network theorems and calculating techniques provide the basis for valid methods of solving power system circuit problems.

### 6.6.2 Linearity

Linearity (see Griffith [B11] and Hoyt and Kennedy [B17]) is the most fundamental concept to be discussed, and is a powerful extension of Ohm's law. Examination of Figure 21 will assist in understanding

the basic principles. The simplified network is represented by the single impedance element, $R$ + jX. The circuit diagram shown is said to be linear for the chosen excitation and response function. A plot of the response magnitude (current) versus the source excitation magnitude (voltage) is a straight line for a linear element. This is the situation shown for plot “A” (solid line) in the graph at the bottom of the figure. When linearity exists, the plot applies to either the steady-state value of the excitation and response functions or the instantaneous value of the functions at a specific time.

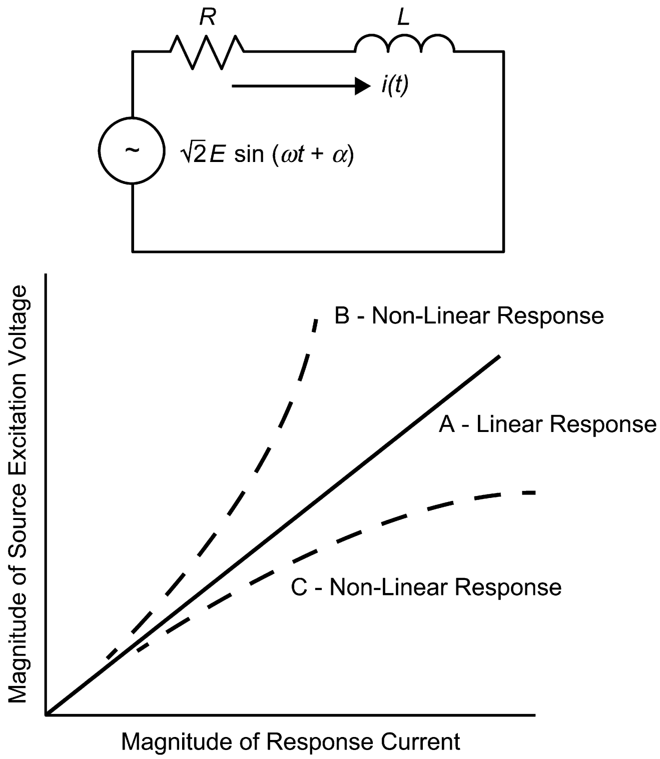



**Figure 21 —Linearity**

When linear dc circuits are involved, the current will double if the voltage is doubled. The linear characteristic also holds for ac circuits provided the frequency of the driving voltage is held constant. In a similar manner, it is possible to predict easily the response of a constant impedance circuit (i.e., constant *R, L*, and *C* elements) to any magnitude of dc source excitation or fixed frequency sinusoidal excitation based on the known response at any other level of excitation. For the chosen excitation function of voltage and the chosen response function of current, either dotted curve “B” or “C” would be examples of the response characteristic of a non-linear element. Such non-linear characteristics are often encountered in the modeling of rotating machines and transformers, and the engineer must be aware of the potential effects.

An important limitation of linearity is that the excitation source, if not independent, must linearly depend on another (independent or dependent) source or network variable. Ultimately in a linear circuit, all variables, including source, network, and load voltages and currents are related to each other by a set of coefficients. This restraint, in effect, forces a source to behave with a linear response.

### 6.6.3 Superposition

Superposition (see Griffith [B11] and Hoyt and Kennedy [B17]) is possible as a direct result of linearity, and hence is subject to the same restraints. The superposition theorem states that if a network consists of linear elements and has several dc or fixed frequency ac excitation sources (i.e., voltages), the total response (i.e., current) can be evaluated as the sum of the currents caused by each voltage source acting

separately with all other source voltages reduced to zero or, similarly, all other current sources open-circuited. Note that this sum will be a simple algebraic sum in dc circuits, and will be a vector sum in ac circuits.

An example that illustrates this principle is shown in Figure 22. The written equation is for the sum of the currents from each individual source of $V$ = 10 V and $V$ = 5 V. The 2 Ohm and 6 Ohm impedance values represent the sum of internal impedances of the voltage sources and any other impedance in the source branches. The 5 Ohm impedance represents a load impedance.

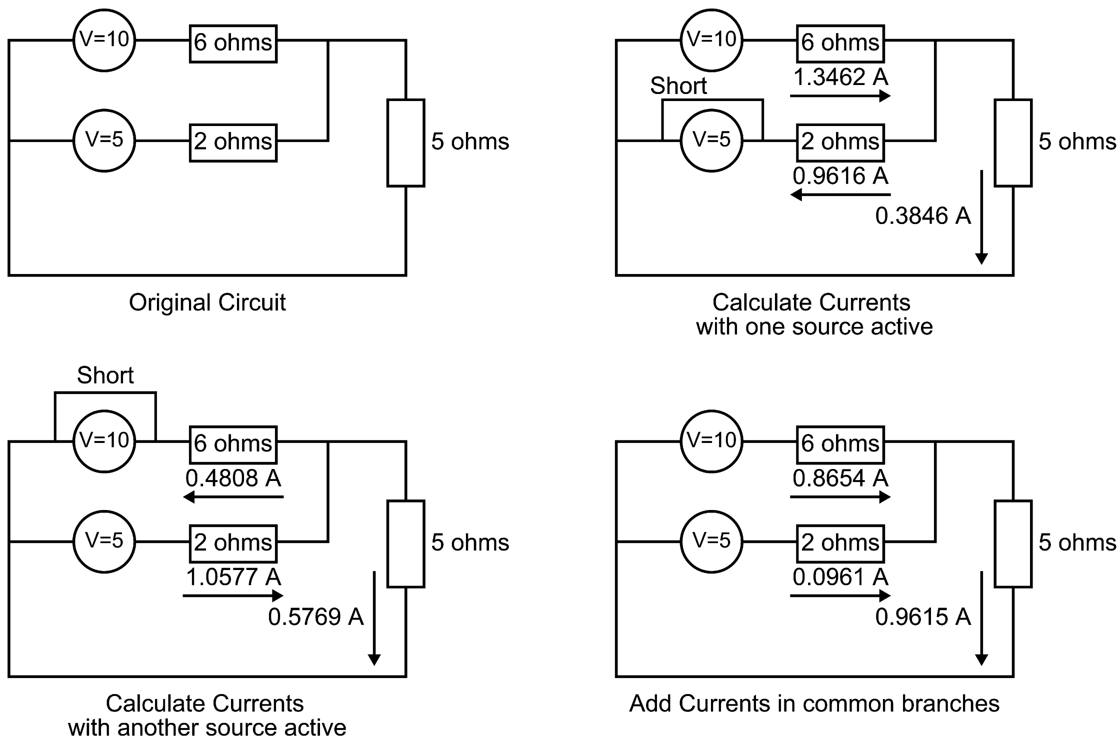



**Figure 22 —Superposition**

### 6.6.4 Thevenin equivalent circuit

This powerful circuit analysis tool is based on the fact that any active linear network, however complex, can be represented by a single-voltage source equal to the open-circuit voltage across any two terminals of interest, in series with the equivalent impedance of the network viewed from the same two terminals with all sources in the network inactivated (i.e., voltage sources zero and current sources open). The validity of this representation requires only that the network be linear. The existence of linearity is, therefore, a necessary restraint. (Note that Thevenin equivalents can also be formed for multiphase power systems.) The application of the Thevenin equivalent circuit can be appreciated by again referring to the simple circuit of Figure 23 and developing the Thevenin equivalent for the network with the switch in the open position as illustrated in the step-by-step procedure. After connecting the 5-Ohm load to the Thevenin equivalent network, the solution is the same as in Figure 22, 0.9615 A. Using the simple Thevenin equivalent shown for the entire left side of the network, it would be easy to examine the response of the circuit as the value of the load impedance is varied. Caution, however, is required to ensure that equipment models or buses of interest are not “absorbed” by the process of forming a Thevenin equivalent. Once absorbed, relevant data pertaining to individual contributions to total short-circuit current and bus voltages are unrecoverable without completely resolving the entire circuit without using an equivalent.

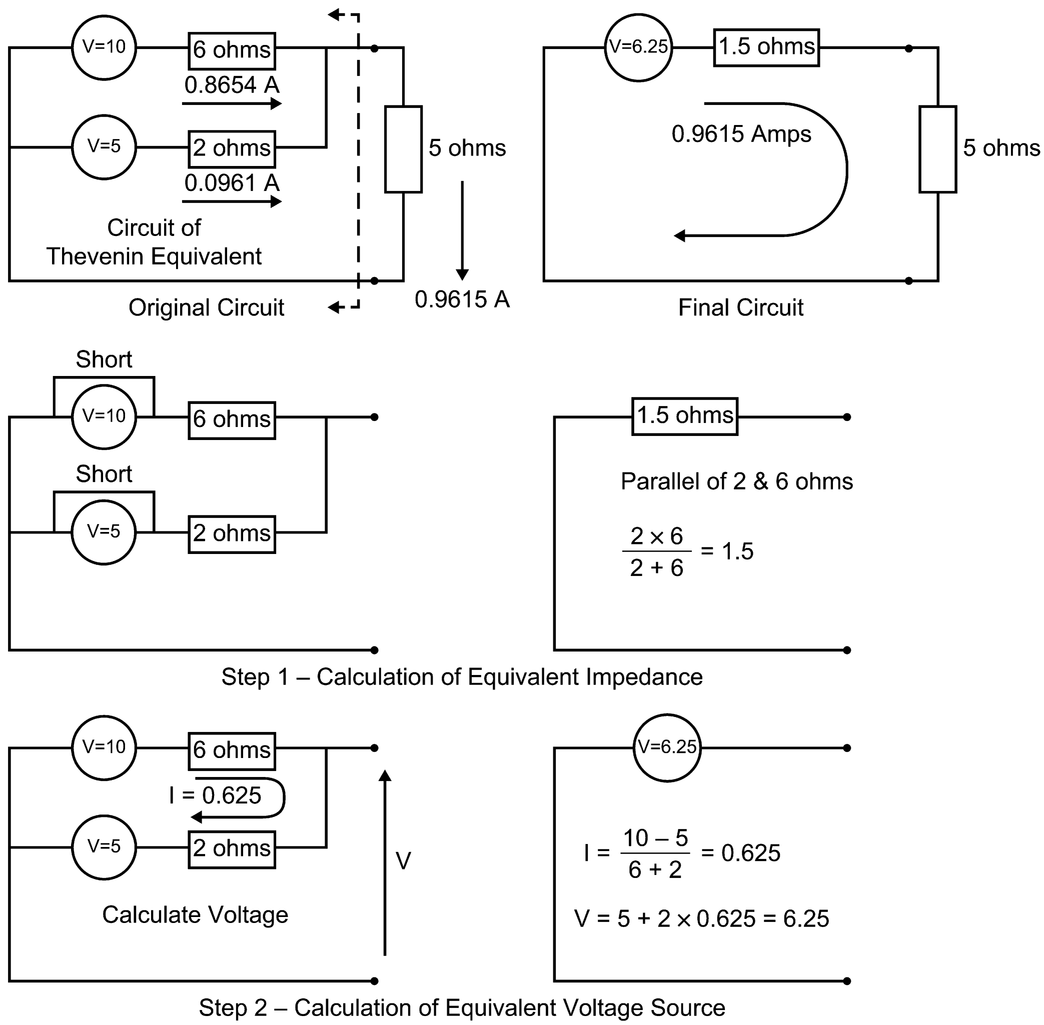



**Figure 23—Thevenin equivalent**

The Thevenin equivalent circuit solution method is equally valid for complex impedance circuits and is the basis for making short-circuit calculations. The actual values for the source voltage and branch impedances would, no doubt, be substantially different from those used in this example.

In the sample circuit, the 2-Ohm branch of the circuit could correspond to the utility supply through a transformer, while the 6-Ohm branch may represent a generator connected to the load bus. A bus fault shorting out the load will result in a current of 6.25/1.5 = 4.1667 A.

The network shown in Figure 23 may well serve as an oversimplified representation of a power system equivalent circuit. As previously mentioned, if the terminals experience a bolted fault, without knowing the details of the original circuit, there is no way of knowing that fraction of the total circuit is supplied from each source in the original circuit.

### 6.6.5 Norton equivalent circuit

A Norton equivalent, Figure 24, consists of a current source (triangle) in parallel with an equivalent impedance can alternately be developed for the Thevenin equivalent circuit. This representation is often used for computer solutions, but generally not for “by hand” solutions in power system analysis work.

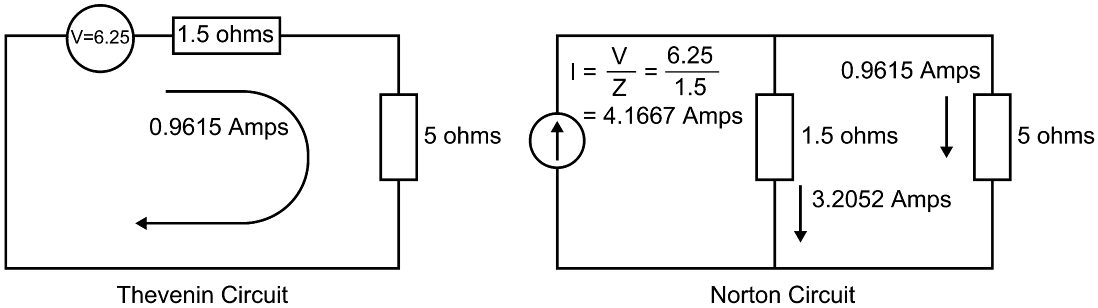



**Figure 24—Norton equivalent for a Thevenin equivalent circuit**

### 6.6.6 Millman's theorem

A direct result of Norton's equivalent is Millman's theorem (see Fich and Potter [B10]), which states that when any number of voltage sources of arbitrary generated voltage and finite internal impedance different from zero are connected in parallel, the resultant voltage across the parallel combination is the ratio of the algebraic sum of the currents that each source individually delivers when short-circuited to the algebraic sum of the internal admittances. Millman's theorem can be used to simplify calculations in polyphase circuits and has other applications.

### 6.6.7 Reciprocity

The general reciprocity (see Fich and Potter [B10]) theorem states that in networks consisting of linear circuit elements, the ratio of excitation to response when only one excitation is applied is constant when the positions of excitation and response are interchanged. Specifically, this means that the ratio of the voltage applied in one branch to the resulting current in a second branch of a network is the same as the ratio of the voltage applied in the second branch to the resulting current in the first branch.

### 6.6.8 Sinusoidal forcing function[7]

It is a most fortunate truth that the excitation sources (i.e., driving voltage) for electrical networks, in general, have a sinusoidal character and may be represented by a sine wave plot of the type as previously illustrated in Figure 12 and Figure 13. There are two important consequences of this circumstance. First, although the response (i.e., current) for a complex *R, L, C* network represents the solution to at least one second-order differential equation, the steady-state result will be a sinusoid of the same frequency as the excitation and differs only in magnitude and phase angle.

The second important item is that when the sinusoidal current is forced to flow in a general impedance network of *R, L,* and *C* elements, the voltage drop across each element will have a sinusoidal shape of the same frequency as the source. The sinusoidal character of all the circuit responses makes the application of the superposition technique to a network with multiple sources surprisingly manageable. The necessary manipulation of the sinusoidal terms is easily accomplished using the laws of vector algebra.

The only restraint associated with the use of the sinusoidal forcing function concept is that the circuit must be composed of linear elements. While most circuits contain nonlinearities, it is usually possible to restrict an analysis to a certain range of operating conditions where linear characteristic hold.

[7] See Griffith [B11].

### 6.6.9 Phasor representation[8]

Phasor representation allows any sinusoidal forcing function to be represented as a phasor in a complex coordinate system in the manner shown in Figure 25. The expression for the phasor representation of a sinusoid may assume any of the following shorthand forms:

Exponential: $Ee^{j\phi}$

Rectangular: $E\,(\cos\phi + \mathrm{j}\sin\phi)$

Polar: $E\angle\phi$

These three forms are related as shown in Equation (40):

$$Ee^{j\varphi} = E(\cos\varphi + \mathrm{j}\sin\varphi) = E\angle\varphi \tag{40}$$

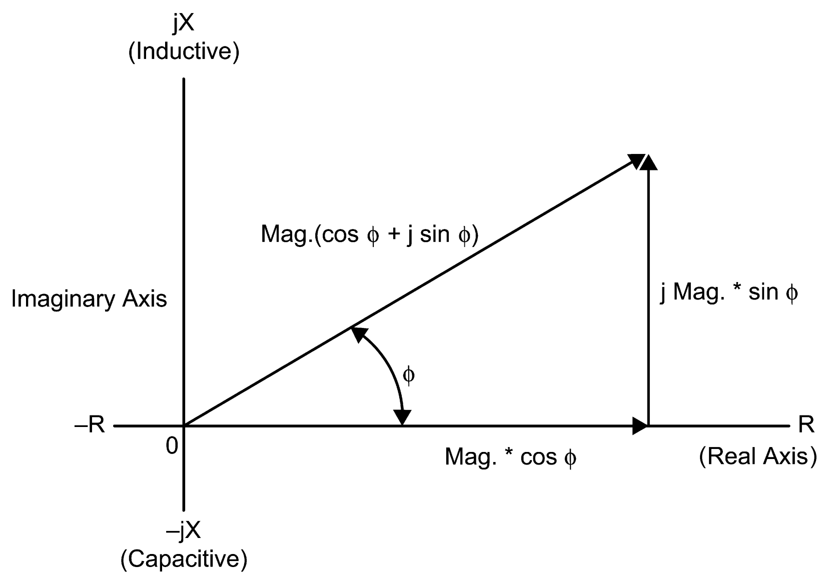



**Figure 25—The phasor diagram**

The network impedances can be represented as phasors using vectorial relationships and the circuit current responses can be obtained through the simple vector algebraic manipulation of the quantities involved. The need for solving complex differential equations in order to determine the steady-state circuit response is completely eliminated.

The following restraints apply:

a) The sources must all be sinusoidal.

b) The frequency must remain constant.

c) The circuit *R, L,* and *C* elements must remain constant, i.e., linearity must exist.

[8] See Griffith [B11].

### 6.6.10 Fourier representation[9]

This tool allows any non-sinusoidal periodic function to be represented as the sum of a dc component and a series (infinitely long, if necessary) of ac sinusoidal functions. Figure 26 shows a non-sinusoidal waveform without a dc component. The ac components have frequencies that are an integral harmonic of the fundamental frequency. The general mathematical form of the so-called "Fourier Series" is as shown in Equation (41).

$$f(t)=F_0+\sum_{n=1}^{\infty}\sqrt{2}F_n\cos\left(n2\pi f_0 t+\theta_n\right) \tag{41}$$

where

$F_0$ is a dc term

$F_1$ is a fundamental frequency (60 Hz in North American power systems) term

$F_n$ are called *harmonics* of the fundamental and have frequency of $n2\pi f_0$; each harmonic may have some nonzero phase angle $\theta_N$

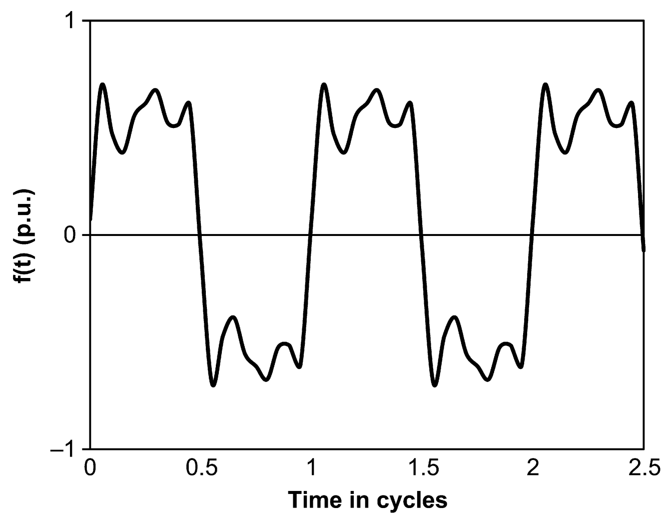



**Figure 26—The Fourier representation**

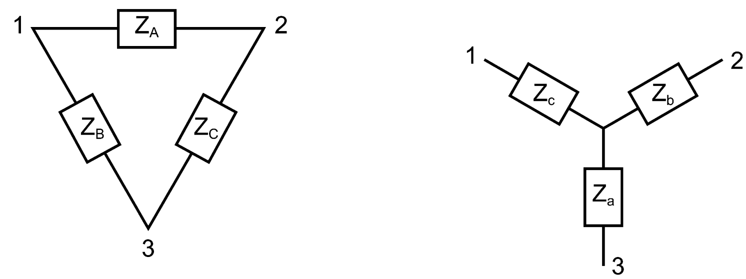
The importance of the Fourier representation is that the response to the original driving function can be determined by first appropriately solving for each harmonic component driving function and then summing all the individual solutions to find the total response by superposition. Because each of the component response solutions is readily obtained, the most difficult part of the problem becomes the modification of reactance and capacitance of the network for each harmonic and the solution of the component driving function. The individual harmonic voltages can be obtained in combination with numerical integration approximating techniques through several well-established mathematical procedures. The discussion of their use is better reserved for the many excellent texts on the subject.

There are several rather abstract mathematical conditions that must be satisfied to permit the use of a Fourier representation. The practical restraints are that the original driving function must be periodic (repeating) and the network must remain linear for each of the frequencies in the non-sinusoidal wave form.

[9] See Griffith [B11].

### 6.6.11 Equivalence

The Equivalence theorem (see Fich and Potter [B10]) states that at any given frequency, any passive four-terminal network can be replaced by an equivalent star or delta network. This fact is very useful in short-circuit calculations to reduce a system consisting of many current loops and voltage nodes to a simple equivalent circuit. Figure 27 shows the equations for both delta-star and star-delta transformations.




$$Z_a = \frac{Z_B\, Z_C}{Z_A + Z_B + Z_C} \qquad Z_A = Z_b + Z_c + \frac{Z_b\, Z_c}{Z_a} = \frac{Z_a\, Z_b + Z_b\, Z_c + Z_c\, Z_a}{Z_a}$$

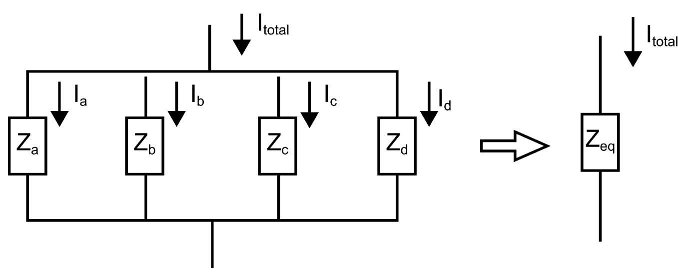
$$Z_b = \frac{Z_A\, Z_C}{Z_A + Z_B + Z_C} \qquad Z_B = Z_a + Z_c + \frac{Z_a\, Z_c}{Z_b} = \frac{Z_a\, Z_b + Z_b\, Z_c + Z_c\, Z_a}{Z_b}$$

$$Z_c = \frac{Z_A\, Z_B}{Z_A + Z_B + Z_C} \qquad Z_C = Z_a + Z_b + \frac{Z_a\, Z_b}{Z_c} = \frac{Z_a\, Z_b + Z_b\, Z_c + Z_c\, Z_a}{Z_c}$$

**Figure 27 —Delta-star impedance conversions**

### 6.6.12 Parallel impedances

Where two or more impedances are paralleled and $Z_{\text{equiv.}}$ equals the equivalent impedance, the relationships shown in Figure 28 are valid. In the case of two impedances, the expression is reduced to the product of the two impedances divided by the sum.




$$\frac{1}{Z_{\text{equiv.}}} = \frac{1}{Z_a} + \frac{1}{Z_b} + \frac{1}{Z_c} + \frac{1}{Z_d} \qquad I_a = \frac{I_{\text{total}} \times Z_{\text{equiv.}}}{Z_a}$$

Special Case of Two Impedances

$$Z_{\text{equiv.}} = \frac{Z_a \times Z_b}{Z_a + Z_b} \qquad I_a = I_{\text{total}} \times \frac{Z_b}{Z_a + Z_b}$$

**Figure 28 —Parallel impedances**

## 6.7 Symmetrical components—modeling method for unbalanced faults calculation

### 6.7.1 Introduction

An unbalanced fault condition is the most common circuit condition that requires more complex analysis than using the single-phase (positive sequence) equivalent circuit condition method to calculate short-circuit current. The use of symmetrical components is the analytical technique most commonly used under these circumstances. Unbalanced faults, such as line-to-ground faults, line-to-line faults, and double line-to-ground faults require the use of symmetrical components for the calculation of the short-circuit currents. Symmetrical components are used to reduce an unbalanced system of phasors into three balanced systems of phasors designated as positive, negative, and zero sequence components. Figure 29 is an illustration of the system of symmetrical components. The subscripts A, B, and C represent the three phases of voltage and the subscript 1 represents the positive sequence components.

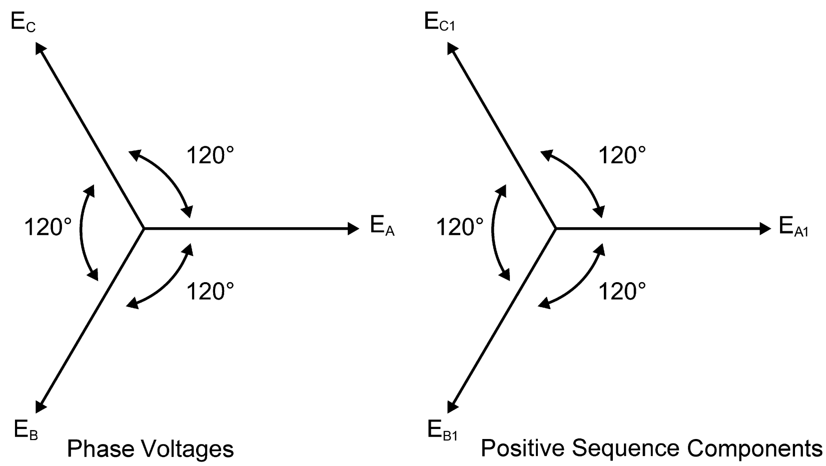



**Figure 29—Symmetrical component balanced phasors**

Any three-phase set of unbalanced voltage phasors (or current phasors) can be resolved into three-balanced or symmetrical sets of phasors, i.e., positive sequence symmetrical components, negative sequence symmetrical components, and zero sequence components (subscripts 1, 2, and 0 respectively), as shown in Figure 30.

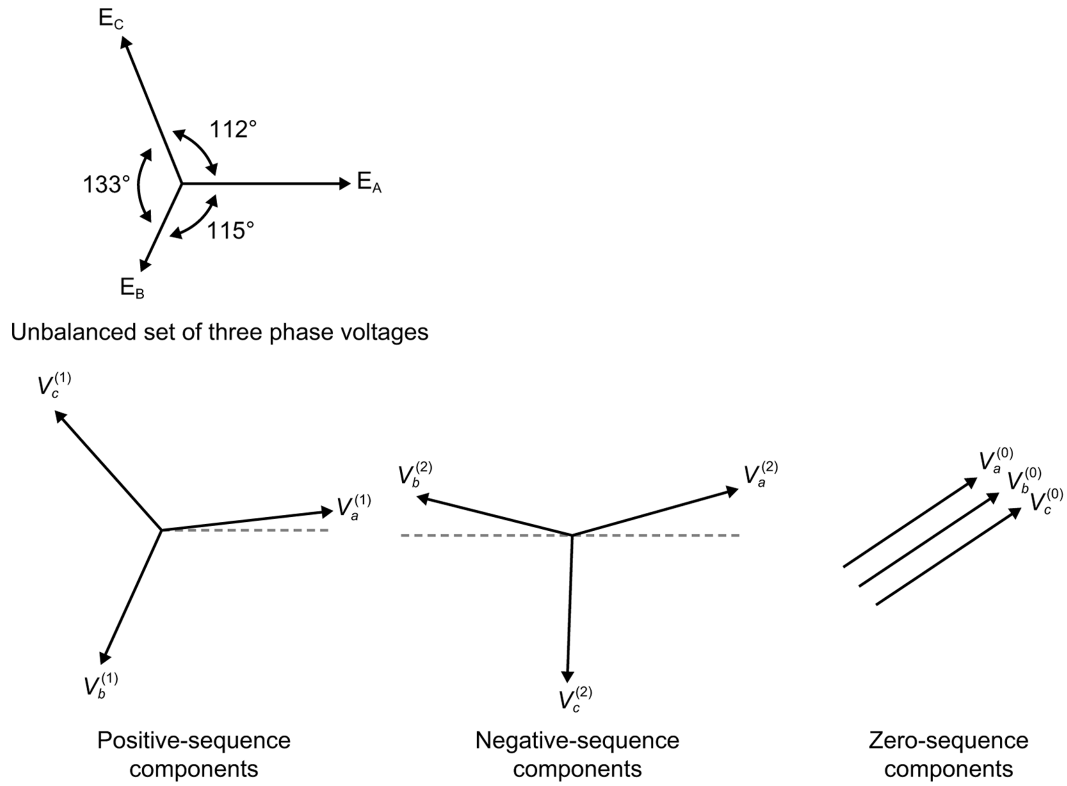



**Figure 30—Symmetrical components of unbalanced phasors**

Symmetrical component techniques allow the user to solve for voltages and currents in balanced sequence networks, and then convert the solution back to actual currents and voltages. The relationship between the phase quantities in terms of their symmetrical components is given below. Values of current can be substituted in place of the voltage in the equation without any conversion factors. The equations are normally given as a set of three to represent the individual phases.

$$\begin{aligned} E_{\boldsymbol{a}} &= E_{\boldsymbol{a}0} + E_{a1} + E_{a2} = E_{a0} + E_{a1} + E_{a2} \\ E_{\boldsymbol{b}} &= E_{\mathrm{bo}} + E_{\mathrm{b}1} + E_{\mathrm{b}2} = E_{a0} + E_{a1}\angle 240 + E_{a2}\angle 120 \\ E_{\mathrm{c}} &= E_{co} + E_{\mathrm{c}1} + E_{\mathrm{c}2} = E_{a0} + E_{a1}\angle 120 + E_{a2}\angle 240 \end{aligned} \tag{42}$$

When using symmetrical components, it is convenient to define an operator ***a*** such that:

$$a = 1\angle 120 = -0.5 + \mathrm{j}0.866$$

$$a^2 = 1\angle 240 = -0.5 - \mathrm{j}0.866$$

Note that vector ***a*** is an operator with unit length and is oriented 120° in counter-clockwise rotation from reference axis. Figure 31 shows the property of $\boldsymbol{a}_0$, $\boldsymbol{a}_1$, $\boldsymbol{a}_2$, and so on.

Using the operator ***a***, Equation (41) can now be rewritten as shown in Equation (43):

$$\begin{aligned} E_{\boldsymbol{a}} &= E_{a0} + E_{a1} + E_{a2} \\ E_{\boldsymbol{b}} &= E_{a0} + a^2 E_{a1} + aE_{a2} \\ E_{\mathrm{c}} &= E_{a0} + aE_{a1} + a^2 E_{a2} \end{aligned} \tag{43}$$

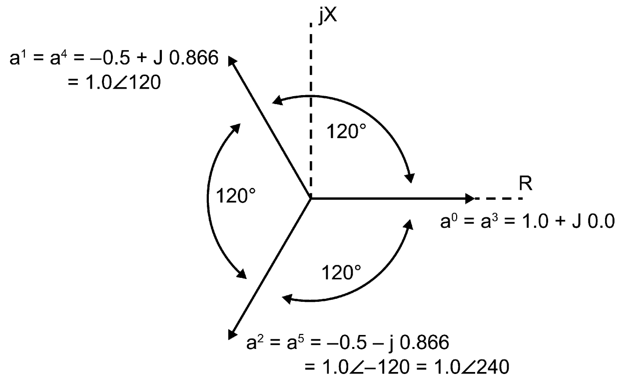



**Figure 31 —Operator ‘a’ vectors**

or in matrix form as in Equation (44):

$$\begin{bmatrix} E_A \\ E_B \\ E_C \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \begin{bmatrix} E_{a0} \\ E_{a1} \\ E_{a2} \end{bmatrix} \tag{44}$$

with the matrix A defined as follows in Equation (45):

$$[A] = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix} \tag{45}$$

The inverse of the A matrix is as in Equation (46):

$$[A]^{-1} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \tag{46}$$

and

$$\begin{bmatrix} E_{a0} \\ E_{a1} \\ E_{a2} \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix} \begin{bmatrix} E_A \\ E_B \\ E_C \end{bmatrix} = [A]^{-1}\begin{bmatrix} E_A \\ E_B \\ E_C \end{bmatrix} \tag{47}$$

The equations above were written for the sequence voltages. A similar set of equations can be written for the sequence current by interchanging the voltage symbol for a current symbol. Note that if the zero sequence quantity, $I_{\mathbf{a}0}$ (or $V_{\mathbf{a}0}$), equals zero, then the vector sum of $I_A + I_B + I_C$ (or $V_A + V_B + V_C$) equals zero.

In the use of symmetrical components, the voltage is normally taken as line-to-neutral voltage for the following reason. In an unbalanced set of $E_{L\text{-}L}$ voltage vectors, the sum of voltages around the vector triangle is zero and the identity of zero sequence is not apparent. Based on Equation (47), the zero sequence $E_{L\text{-}L}$ is zero, $E_{\mathbf{a}0} = E_{AB} + E_{BC} + E_{CA}$; however, $E_{\mathbf{a}0}$ using $E_{L\text{-}N}$ voltage may not be zero. The vector diagram in Figure 32 illustrates the point.

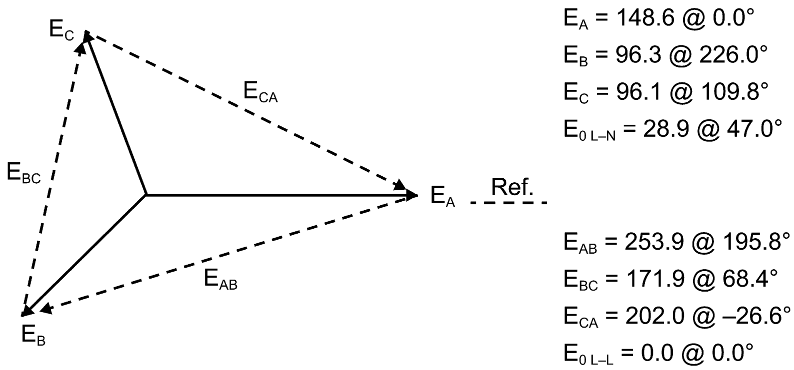



**Figure 32—Zero sequence component of line-to-line and line-to-neutral voltages**

In a grounded power system, the zero sequence impedance completes the circuit by allowing the current to flow in the system neutral or in ground. The magnitude of current in the return path is $3I_{a0}$. Where $3I_{a0} = I_n = I_a + I_b + I_c$. When $3I_{a0} = 0 = I_a + I_b + I_c$, no current flows in the neutral. Note that a three-phase three-wire (ungrounded) system will require $I_{a0} = 0$ because no neutral (or return) path exists for current flow.

It is interesting to note that the delta winding of a delta-wye or wye-delta connected transformer or delta connected loads provide no current path to neutral and no zero sequence currents will exist in delta connected systems. However, it can be shown that zero sequence circulating currents can exist in the delta winding of a transformer but not pass through the transformer.

### 6.7.2 Sequence impedances

The impedance of elements in a symmetrical electrical system may be resolved into positive, negative, and zero sequence components. In a balanced three-phase system, only positive sequence impedances are required and only positive sequence voltage drops and current flows result from the analysis. (Recall the equivalence of the positive sequence and the "a" phase under balanced three-phase conditions.) In systems where the phase impedances are not equal or where unbalanced faults are simulated using symmetrical networks, positive, negative, and perhaps zero sequence voltage drops and current flows will result.

The relationships between sequence voltages and currents follow Ohm's law as shown in Equation (48) and Figure 33.

$$\begin{aligned} E_1 &= I_1 Z_1 \\ E_2 &= I_2 Z_2 \\ E_0 &= I_0 Z_0 \end{aligned} \tag{48}$$

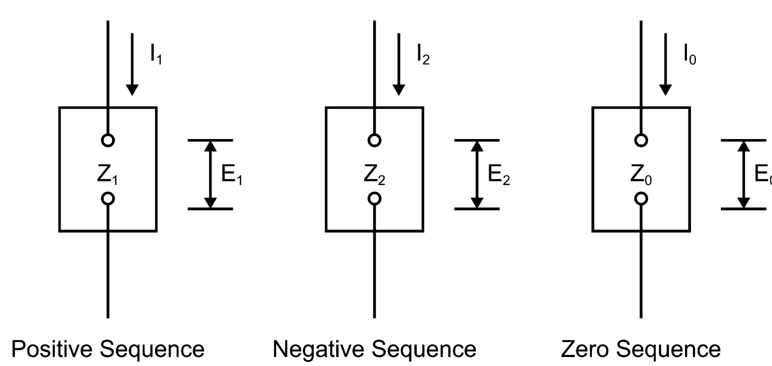



**Figure 33—Sequence network diagrams for Equation (48)**

In general, the impedances of static elements are the same in positive and negative sequences, but may differ in the zero sequence. For rotating machines, the impedances are usually different for all sequences.

Rothe [B59], Stevenson [B60], and Westinghouse [B65] provide positive, negative, and zero sequence impedance representations of the various system components for network calculations.

Figure 34 illustrates how sequence components are obtained for a transformer. The same source connection is used for other equipment. Positive sequence impedances are determined by the use of a balanced three-phase source while zero sequence impedances are determined by connecting all three-phase leads to a common single-phase source.

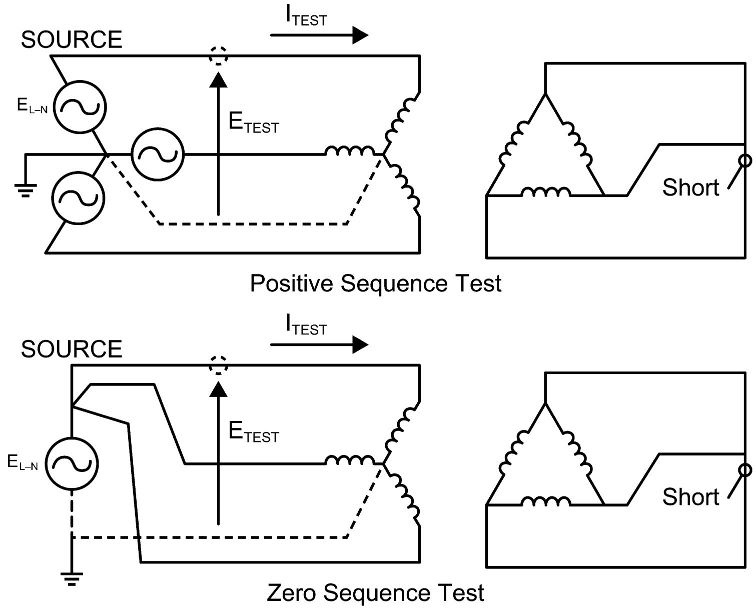



**Figure 34—Test set-up used to obtain the sequence components of a transformer**

## 6.8 Representing transformers with non-base voltages

Occasionally, a power system includes transformers that have voltage ratios that differ from the power system nominal values of base voltage chosen. This difference can have an influence on the calculated fault current levels. The concern is the handling of the transformer impedances and correction due to differences in rated and base voltages. Usually a correction of transformer percent impedance due to a different operating tap other than transformer rated or flat taps is not done unless test data provides this information. Depending upon the design of the tap section of the transformer, the percent impedance of the transformer on other taps is unknown without the transformer tap test data. If there is a change, it is usually not linear or known to vary with any known expression with tap position. Rather than guessing the new value of transformer impedance on other taps, it may be considered a constant.

Several system conditions are possible that will affect the manner in that the transformer per-unit impedance and base voltages are represented in the network. It is easy for the power system engineer to become frustrated, confused, and not make the necessary corrections. Diagrams in Figure 35 through Figure 45 and the explanation below should provide some guidance on this subject. On the diagrams, differences from the rated tap, transformer voltage rating, and base voltage of those used in Figure 35 are noted with a "#". For the condition when the transformer voltages equal the base voltages, nothing needs to be corrected. This includes transformers that are operating off rated taps as shown in Figure 35 and

Figure 37. In all other cases, there could be an impedance or voltage base change depending on how the calculations are done.

In addition, samples are given where the bus operating voltage is different than the base voltage. Most short-circuit calculations assume the prefault bus voltage is equal to the base voltage when an initial load flow calculation is not made. In the following examples, the prefault bus voltage is a concern only for that bus. If the primary voltage is high, as shown in Figure 41, there is no change in the 4.16 kV bus fault level. However, a fault on the transformer primary would be affected by the higher 13.8 kV voltage.

Several conditions exist that will affect the degree to which data changes will have to be made to transformers that have voltages or voltage ratios different than the base voltages. These include manual calculations or the use of computer programs that treat all transformers as if they were on rated taps. An example is the condition shown in Figure 39 where the transformer rated taps and base voltages are equal, but the transformer tap is not equal to the primary base voltage. For the manual calculation, a base voltage and impedance change are required. Also, there will be many cases where no transformer impedance change or base voltage change will be required; these are automatically handled within the computer program.

Transformer taps can be on either side of the transformer. The need to change the transformer impedance will depend on the side of the transformer that the system base voltage is to be held equal to the transformer voltage. In the samples shown, the 13.8 kV (primary side) base voltage was fixed. The sample calculations in the figures use a constant *X/R* ratio of the source and the transformer to keep calculations simple. In cases where the transformer impedance should be modified before being placed in the network, the expression given in Equation (49) (repeated here for convenience) is used. Such a condition occurs when the transformer rated tap voltages do not match base voltages.

$$Z_{Common\ Base} = Z_{Equipment} \frac{kV^2_{LL\ Equipment}}{kV^2_{LL\ Common}} \tag{49}$$

A special case occurs when one of the transformer rated tap voltages matches the base voltages and the second transformer tap does not. In this case, the easiest procedure is to change the base voltage of the side that does not match so that it does. This is easily done on radial systems and will require other base voltages of equipment to be changed so that all impedances are on the same base. In Figure 39 and Figure 42, all impedances on the 4.16 kV side of the transformer will have to be placed on a 4.2667 kV base. Other transformers connected to the 4.16 kV system will have 4.2667 kV as one of the base voltages.

For looped systems, it may not be possible to change the base voltage because different transformers could cause a common bus to have a conflicting base voltage. In this case, the procedure is to choose a base voltage, forcing the non-conforming equipment to fit.

Figure 45 shows a means of transformer representation to force the base voltage, a method used in many computer programs. If the program does not have the facility to model taps, the transformer could be entered as three branches, provided that the program uses a driving voltage and a "ground" or fault bus. The "ground" bus is not the same as the source bus used or "internal voltage" bus used in some programs.

The common configuration is not the best for illustrating the procedure because the fault shorts out one shunt connection of the transformer. A 4.16 kV impedance between the transformer and fault would produce a voltage rise at the secondary of the transformer and some current would flow in that branch.

The transformer tap value is often in per unit of the transformer rated taps with Equation (50).

$$\text{tap value} = \frac{\text{tapped winding rated voltage}}{\text{rated tap voltage}} \tag{50}$$

When the transformer voltage ratio does not equal the base voltage ratio and a program with taps representation is used, then a fictitious tap value can be used to resolve the difference. The expression is shown in Equation (51).

$$\text{fictitious tap value} = \frac{\text{(tapped winding rated tap voltage)(untapped winding base voltage)}}{\text{(untapped winding rated voltage)(tapped winding base voltage)}} \tag{51}$$

The nameplate transformer impedance requires modification if the untapped winding voltage rating does not equal the base voltage.

In the examination of the sample configurations, it appears that the fault duty on the secondary side is not fixed for a given transformer. For a given transformer, it was noted above that the impedance was taken to be constant over the tap range. Given that statement, the fault duty in MVA on the secondary side should be constant. Comparing Figure 35 and Figure 38 shows such conditions where the fault current is different. This is best illustrated by comparing the volt-ampere to the fault. Both Figure 35 and Figure 37 provide the same value.

From Figure 35: $\text{MVA} = 17.35 \times 4.16 \times \sqrt{3} = 125 \text{ MVA}$

From Figure 42: $\text{MVA} = 16.91 \times 4.2667 \times \sqrt{3} = 125 \text{ MVA}$

For circuit breakers applied to 4.16 kV systems, the circuit breakers have a constant volt-ampere capability between its minimum and maximum voltage rating. Therefore, the numbers above are being applied at the same percent of maximum circuit breaker capability.

Figure 40 and Figure 41 have a condition where the transformer tap or high primary voltage would make the secondary prefault voltage high if no load was placed on the transformer. In these cases, it was assumed that the voltage was the result of a power flow calculation and the prefault current flow through the transformer resulted in the bus voltage being one per unit. Using the no-load prefault voltage would result in the fault currents being higher by the ratio of (no load voltage/prefault voltage). Figure 40 would equal 17.57 kA and Figure 41 would equal 17.85 kA.

In Figure 35 through Figure 45 the term

$$\frac{\text{base kV ratio}}{\text{transformer kV ratio}}$$

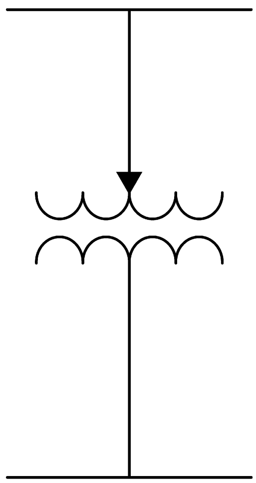
is defined as

$$\text{base kV ratio} = \frac{\text{base kV at transformer primary}}{\text{base kV at transformer secondary}}$$

and

$$\text{transformer kV ratio} = \frac{\text{transformer primary tap kV}}{\text{transformer secondary tap kV}}$$

Source Short-Circuit MVA = 500



Base kV = 13.8
Base MVA = 10
Zs = 10 / 500 — Zs = 0.02 pu

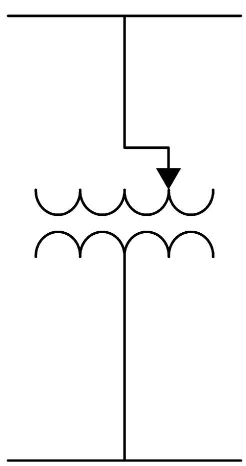
Transf. MVA = 10
Transf. kV Rating = 13.8 - 4.16
Transf. Impedance = 6% — $Z_T$ = 0.06 pu

Transf. Tap = 13.8 kV
Base kV Ratio = Transf. kV Ratio
Base kV = 4.16

Ztotal = 0.08 pu
Prefault Voltage = 1.0 pu — If = 1.0 / 0.08 = 12.5 pu
Prefault Voltage = 4.16 kV — If = 12.5 * 10 / 4.16 $\sqrt{3}$
= 17.35 kA

**Figure 35—Transformer kV equals base kV; transformer rated kV ratio equals base kV ratio**

Source Short-Circuit MVA = 500



Base kV = 13.8
Base MVA = 10
Zs = 10 / 500 — Zs = 0.02 pu

Transf. MVA = 10
Transf. kV Rating = 13.2 - 3.98
Transf. Impedance = 6% — $Z_T = 0.06 * (13.2^2/13.8^2)$
$= 0.0549$

Transf. Tap = 13.2 kV
Base kV Ratio = Transf. kV Ratio
Base kV = 4.16

Ztotal = 0.0749 pu
Prefault Voltage = 1.0 pu — If = 1.0 / 0.0749 = 13.351 pu
Prefault Voltage = 4.16 kV — If = 13.351 * 10 / 4.16 $\sqrt{3}$
= 18.53 kA

**Figure 36—Transformer rated kV not equal to base kV; transformer rated kV ratio equals base kV ratio**

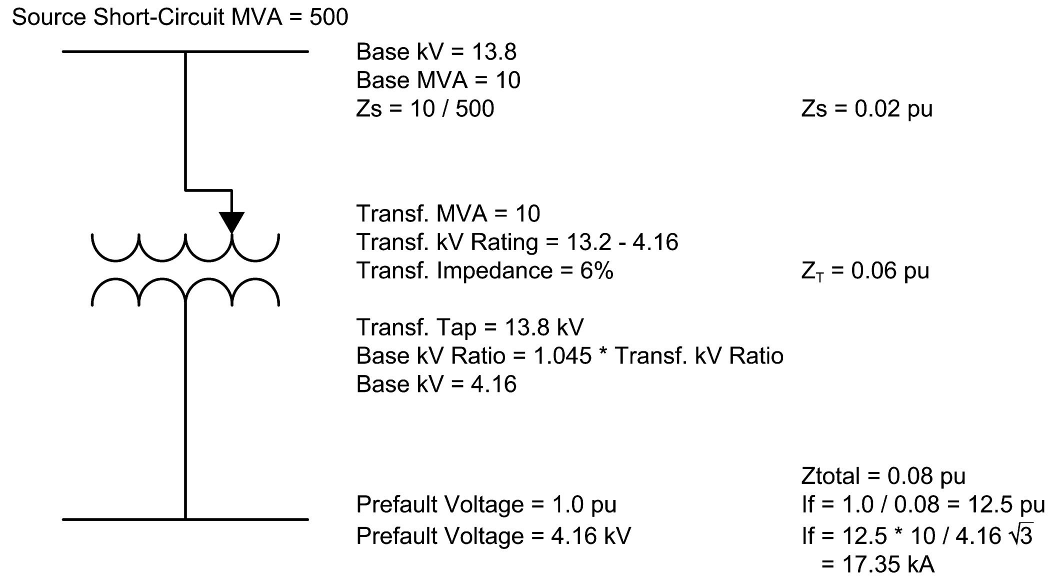



**Figure 37 —Transformer tapped kV equals to base kV; transformer rated kV ratio not equal to base kV ratio**

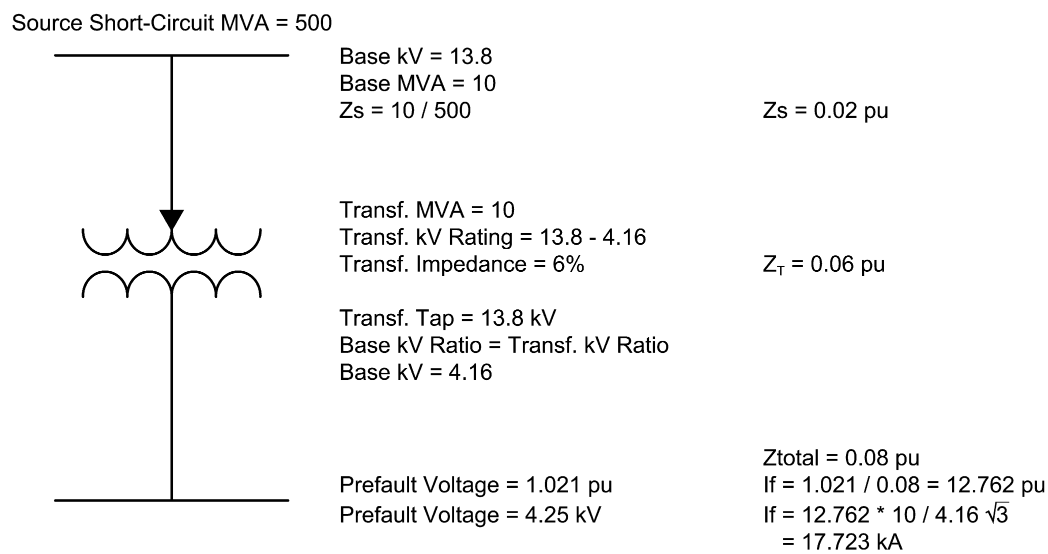



**Figure 38 —Transformer rated and tapped kV ratio equals base kV ratio; secondary prefault kV not equal to bus base kV**

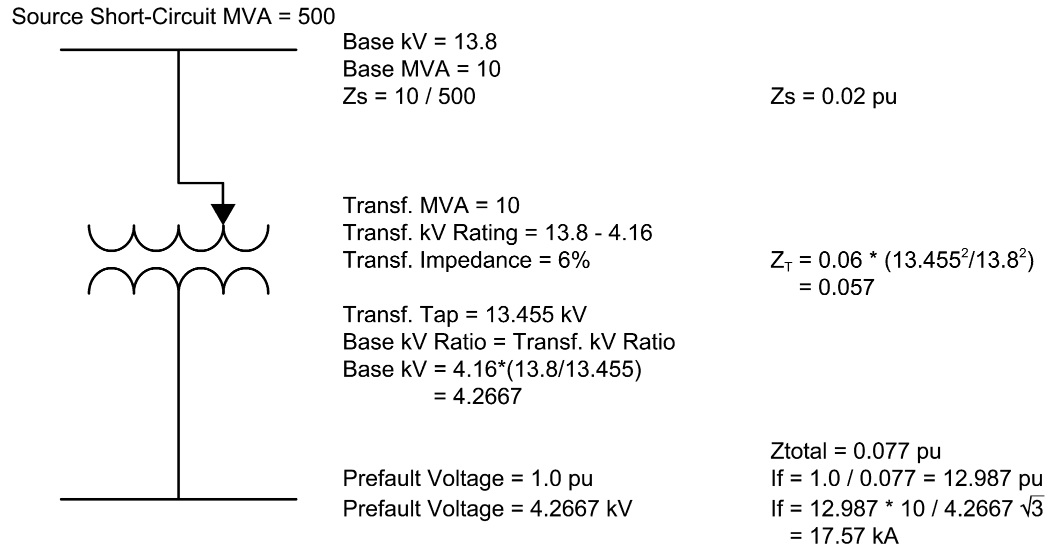



**Figure 39 —Transformer rated kV equals to base kV; transformer tapped kV not equal to base kV; secondary prefault kV not equal to bus base kV**

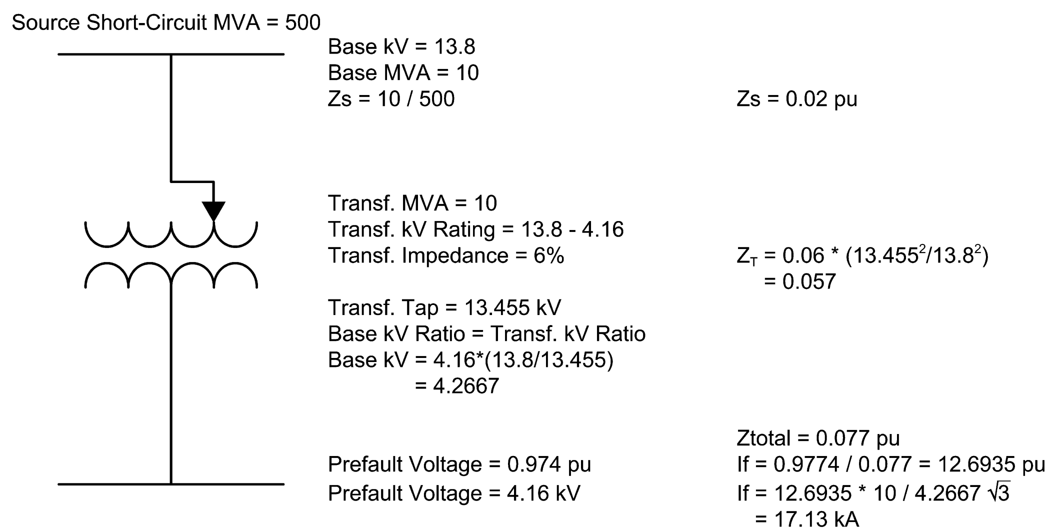



**Figure 40 —Transformer rated kV equals to base kV; transformer tapped kV not equal to base kV; secondary prefault kV equal to bus base kV**

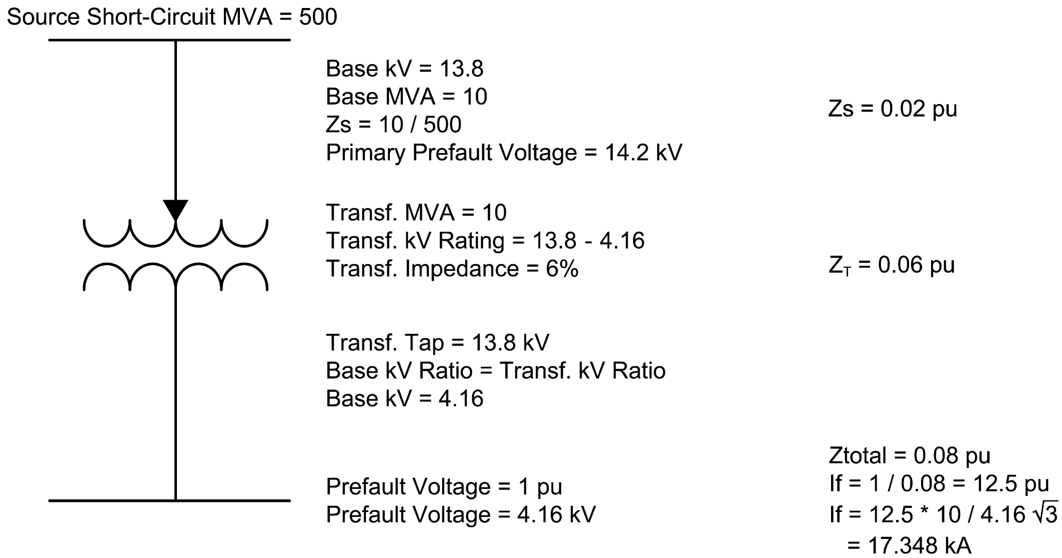



**Figure 41 —Transformer kV equals base kV; transformer kV equals base kV ratio; primary prefault kV not equal to bus base kV**

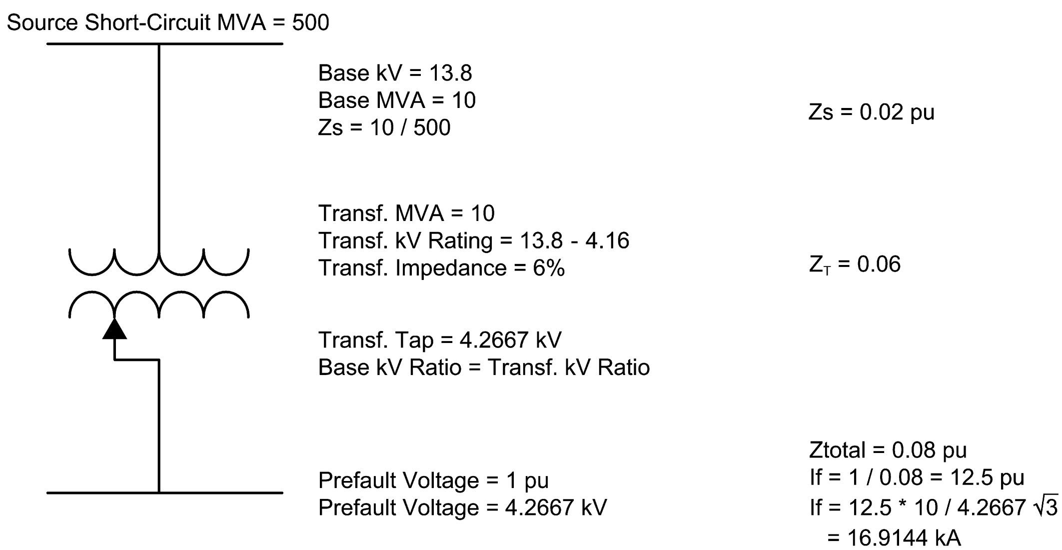



**Figure 42 —Transformer kV not equal to base kV; transformer kV ratio equals base kV ratio**

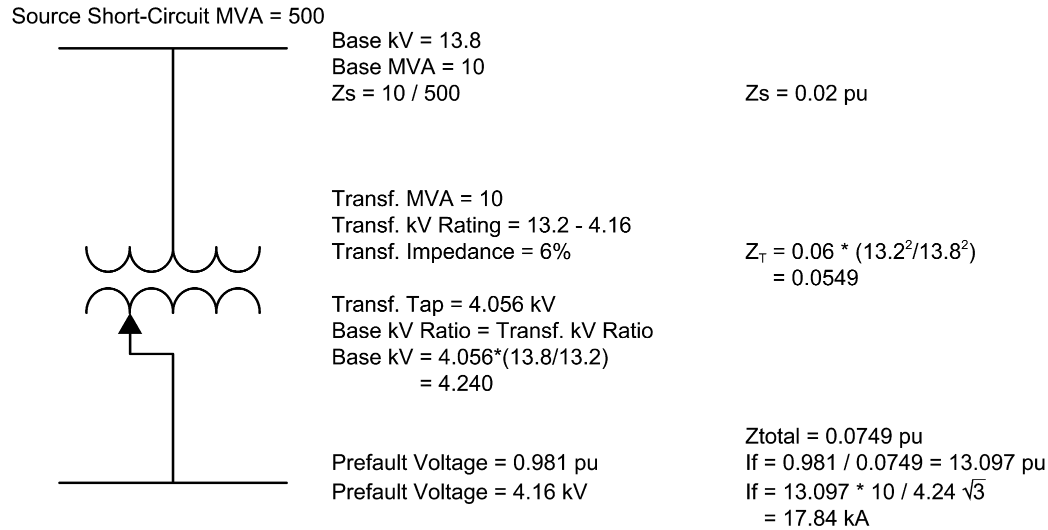



**Figure 43—Transformer tap kV not equal to base kV; transformer rated kV ratio equals base kV ratio; secondary prefault voltage not equal to base kV**

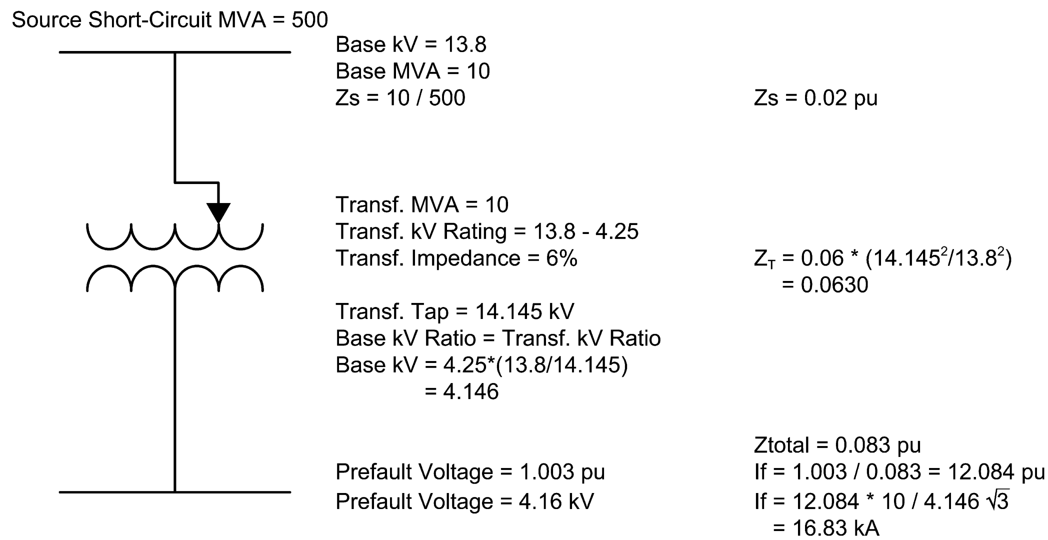



**Figure 44—Transformer tap kV not equal to base kV; transformer kV ratio equals base kV ratio; secondary prefault voltage not equal to base kV**

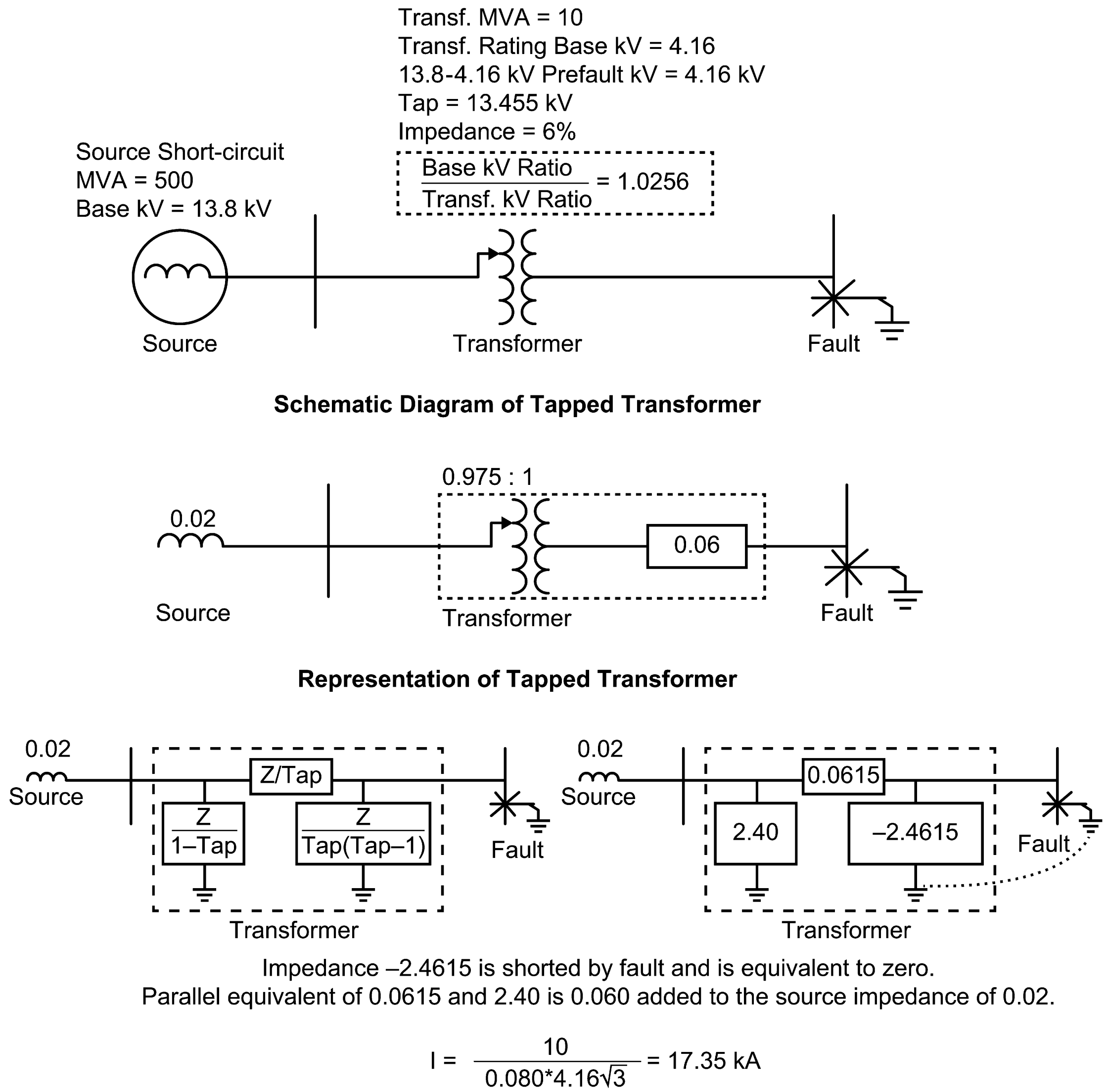



**Figure 45—Transformer tap kV not equal to base kV; transformer kV ratio not equal to base kV ratio**

## 6.9 Specific time period and variations on fault calculations

Short-circuit calculations used in industrial and commercial power systems have several purposes. One purpose is to establish the maximum calculated available short-circuit duties to be compared with the equipment short-circuit ratings or capabilities. Bolted three-phase short-circuits are normally assumed. First-cycle maximum symmetrical duties are used to compare equipment with first-cycle equipment ratings (momentary or close-and-latch) when rated on a symmetrical current basis, while total (asymmetrical) duties are required for equipment rated on a total current basis. In either case, the *X/R* ratio of the fault is also required to calculate the asymmetry of the short-circuit current to ensure that the maximum possible current (ac plus dc) does not exceed equipment ratings. Short-circuit current magnitudes evaluated at times ranging from 1.5 to 4 cycles at 60 Hz are used to determine the interrupting duties for ac medium- and high-voltage circuit breaker applications.

The second purpose is to establish currents useful for protective relaying. Both minimum and maximum currents at the point of fault and as distributed through the system are of interest. Three-phase, line-to-ground, and other types of fault studies may be required. First-cycle maximum short-circuit currents may be used when providing settings for instantaneous or high-speed relays. The currents at longer times after short-circuit initiation are needed for relay settings and also for estimating the performance of time-delay relays. Currents calculated at approximately 30 cycles are recommended to be used for back-up time-delay relays. Often the current values after 30 cycles following the fault initiation are desired for both maximum and minimum generating or operating conditions.

The first-cycle short-circuit currents are also used in determining the magnetic forces that the equipment will be subjected to until the short-circuit is cleared. As previously mentioned, these forces are a function of the instantaneous values of current squared.

The maximum value is the crest value of the maximum asymmetric current that the circuit can produce. It is available in the first half-cycle after the short-circuit occurs. Equipment nameplate data does not provide the magnetic force data directly. Instead, the maximum magnetic forces are indirectly given by the maximum current the equipment can carry.

The total duration of the short-circuit determines the thermal energy available to be released in the equipment.

This energy is a function of the amplitude of the current and the time duration.

The thermal energy:

$$T_e = R\int i^2 dt \text{ Joules} \tag{52}$$

where

$R$ is the equipment resistance

It can be shown that the energy content is a function of the system *X/R* ratio because the total current (ac plus dc) must be accounted for in the evaluation of the thermal energy produced. Again, equipment nameplate data does not provide the thermal energy and magnetic force data directly, but is encompassed by the equipment maximum current carrying capacity and the time that this current is allowed to flow.

The equivalent impedance to be used for calculating fault currents at different time periods is shown in Table 4. The reactance values are general and may differ between standards. The applicable ANSI-approved standards specify the impedance multipliers that should be applied to the rotating machine impedances in the equivalent circuit. These values are given in ANSI C37.010.

In Table 4, depending on the purpose of the calculation, $X''_{\mathrm{d}}$ (modified) may be used with a multiplier in some cases, and in other cases $X'_{\mathrm{d}}$ is being used.

**Table 4—Appropriate reactance values for the different cycles**

| Equipment | First-cycle currents | 1.5- to 4-cycle currents | 30-cycle currents |
|---|---|---|---|
| Utility source | $X_s$ | $X_s$ | $X_s$ |
| Generator | $X''_d$ | $X''_d$ | $X'_d$ |
| Synchronous motor | $X''_d$ (modified) | $X''_d$ (modified) / $X'_d$ | $\infty$ |
| Induction motor | $X''$ (modified) | $X''$ (modified) / $X'$ | $\infty$ |

When the maximum value of short-circuit current 30 cycles after fault initiation is desired, the equivalent circuit (used like a Thevenin equivalent) should include positive sequence impedances yielding toward maximum current magnitudes. In addition, the circuit should include any rotating machines that might still be contributing to the short-circuit fault. This equivalent circuit usually contains generators represented by transient impedance and minimum utility system impedances representing maximum available short-circuit currents.

Induction machines close to the fault will normally either have been disconnected by their undervoltage devices, or the magnetic energy stored in the motor will be completely decayed and hence will not contribute short-circuit currents at 30 cycles.

Depending on the type of excitation systems on synchronous generators or motors, 30-cycle short-circuit current decay associated with synchronous machines still connected to the system will vary greatly. Machine excitation systems that rectify the ac bus voltage for field current may decay to near zero during a nearby fault, while other excitation systems capable of current forcing could provide 1.5 to 3 times full load current at 30 cycles. For maximum short-circuit current, some engineers include these machines using transient impedances in the equivalent circuit.

For faults with durations of 30 cycles or more and also in close proximity to rotating synchronous machines, they will most likely cause the synchronous machine to pull out of step with the remainder of the system. In such cases, a dynamic model of the system would be required for more accurate results.

It should be noted that the maximum line-to-line or line-to-ground short-circuit current can become greater than the maximum three-phase short-circuit current for a persistent fault because the positive sequence impedance of the equipment is increasing while the negative and zero sequence impedances remain constant. Also, the zero sequence impedance may be smaller than the positive and negative sequence impedance at the time of fault initiation.

When the minimum value of a 30-cycle bolted three-phase short-circuit current is required in checking relay operation, the equivalent circuit should simulate operating conditions that tend to minimize short-circuit currents, and should include the minimum number of generators connected and the maximum utility source impedance value representing the minimum available short-circuit currents. Generators are generally represented by transient impedances. Induction machine and synchronous motor contributions are omitted.

## 6.10 Determination of *X/R* ratios for fault calculations

The dc component of fault current decays at a time constant related to the *X/R* ratio at the fault location. This *X/R* ratio depends on short-circuit contributing sources and system network and it varies with fault time. In a looped system or a radial system with multiple sources, the accurate decay rate can only be calculated from the system differential equations. As a common practice, an equivalent *X/R* is used to calculate the decay rate of the dc component of fault current.

There are several methods used for the equivalent *X/R* ratio calculation. For ANSI short-circuit calculations, this *X/R* ratio is found from separate *X* only and *R* only networks derived from the equivalent circuit as described in IEEE Std C37.010-1999, subclause 5.3.2. For IEC short-circuit calculations, there are three methods for this *X/*R ratio calculation:

a) The uniform ratio *X/R*

b) The ratio *X/R* at the short-circuit location

c) The equivalent frequency fc

Method c) is recommended for meshed networks, per IEC TR 60909-1. Clause 10 gives detailed description of the IEC method.

There is no completely accurate means of combining two or more parallel circuits with different values of *X/R* into a single circuit with one value of *X/R*. The current from individual branches of the parallel circuits and sources behind them will be the sum of several exponentially decaying terms, usually with different decay rates, while the *X/R* ratio calculated from a single Thevenin equivalent circuit contains just one such term.

For radially-fed circuits, there will be no difference between solving for the fault point *X/R* ratio using either the $X_{\text{only}}$ and $R_{\text{only}}$ approach or the (single) Thevenin equivalent approach. (Note that *radially-fed* means that there is only one source of fault current.) However, even the addition of a single motor at the end of a radial feeder with a significantly different machine *X/R* ratio as compared to the system impedance will cause a different *X/R* ratio at the fault point between the two calculation methods. It should be noted that an accurate method of determining the fault point *X/R* ratio would be to solve the system differential equations with the system represented with resistors, inductors, and capacitors. Even small systems would become difficult to solve. However, the method of using separately derived networks results in a calculated *X/R* ratio that is generally more conservative (larger) than the (single) Thevenin equivalent method. The Thevenin equivalent method cannot ensure a conservative *X/R* ratio and should not be used for asymmetry current multipliers for circuit breaker duties. However, the use of a Thevenin equivalent should be adequate for relay application.

It should be noted that the resistance network for first-cycle and for interrupting-time calculations is varied for machines by the same multipliers as used for the internal reactance. This caution is noted because some *X* values may have been increased by reactance multiplying factors, and if the corresponding *R* values are not similarly increased, the *X/R* ratio and thus the asymmetrical current multiplying factor will be unrealistically high.

# 7. Equipment modeling for short-circuit calculation

## 7.1 Introduction

The accuracy of short-circuit current calculations is to a large degree dominated by the modeling method used for the system equipment. A too simplistic modeling method may not provide the required result accuracy, while for a too-complicated modeling method, it may not be feasible for end users to obtain parameters. In this clause, modeling for various types of equipment will be discussed based on standards and common accepted practices.

In short-circuit calculations, equipment that need to be considered include:

— Short-circuit contributing sources, including power grid, synchronous generators, synchronous motors, induction machines, and power converters. All short-circuit contributing sources can be

represented as a voltage source behind an impedance. However, in order to account for the decay of the ac components from different machines, the short-circuit current impedance values are modeled as time varying.

- Power transmission equipment, including transmission lines, cables, reactor, transformers, etc. Sometimes equivalent impedance can also be used when the impedance value of a line or cable is given. The general modeling of these equipment types in short-circuit calculations are similar to that in the load flow calculations, except the handling of parameter tolerance. To arrive at more conservative results, when performing maximum short-circuit current calculations, the tolerance values are applied so that slightly smaller impedance values are used. While in minimum short-circuit current calculations, the tolerance values are applied so that slightly higher impedance values are used, which is the same as in load flow calculations.
- Protective devices, including circuit breaker, fuse, switch, etc. The protective devices do not affect short-circuit calculation results. They are used in device duty for device rating verification.
- Shunt capacitor banks. Although capacitors may store energy that is discharged during a short-circuit condition, the time constant of the discharge current is so short that capacitors are not considered as contributors for the purpose of short-circuit calculations.

## 7.2 Power grid

An equivalent representation of a utility system (or power grid) often consists of a large number of machines interconnected by the transmission system. To the local system under the short-circuit study, a power grid is a strong short-circuit source that can provide constant fault current to a fault in the local system. In the short-circuit calculation, a power grid is generally modeled as a constant voltage behind an impedance. This impedance stays constant through the duration of fault, which means that the ac fault current from a power grid does not decay.

The power grid model needs to be obtained from the utility company. It is normally provided in one of these two forms:

a) Short-circuit MVA and *X/R* ratio for a fault at the interface point of the power grid and the local system
b) Impedance in percent on 100 MVA base

For an industrial or commercial power system, the interface point of a power grid and the local system is the entry point of the utility power supply, which is normally either at the secondary side of utility power transformer, or the user end of utility power transmission line. The short-circuit contributions from the utility for a fault at the entry point usually vary depending on the operating conditions of the power grid and the local system. This is especially true if the interface point is the secondary side of utility power transformer and the transformer tap position varies with operating conditions of the local system. It is important to obtain the power grid short-circuit contributions under maximum and minimum fault current conditions.

## 7.3 Synchronous machines

### 7.3.1 Introduction

A synchronous machine is also modeled by a constant voltage source behind impedance. For a fault located electrically close to a synchronous machine, the ac component of the fault current from the synchronous

machine decreases with time. This decay is generally represented by increase of synchronous machine impedance values.

### 7.3.2 Nature of synchronous machine contributions

A running synchronous machine that has a bolted three-phase short-circuit suddenly connected across its terminals will contribute currents to the short-circuit. A typical fault current plot (without dc decay) is shown in Figure 46. The plot shows a high initial decay followed by a slower rate of decay and finally a steady-state value.

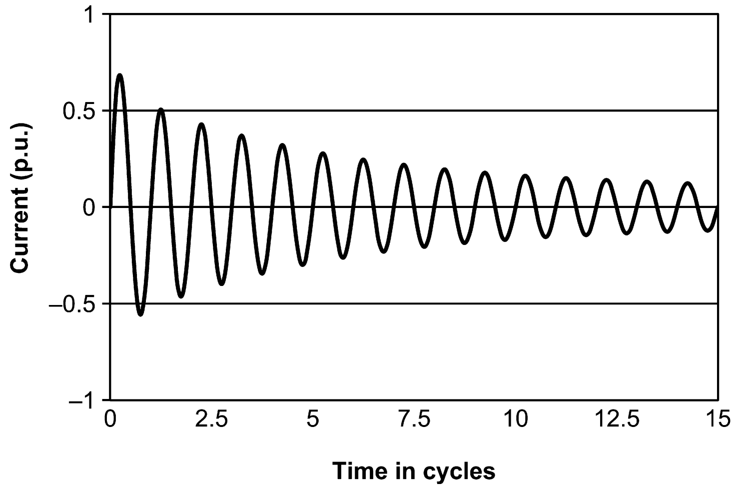



**Figure 46—Three-phase short-circuit currents from a synchronous machine**

The short-circuit current decreases exponentially in time from an initially high value to a lower steady-state level. This happens because the flux across the air gap of the synchronous machine is much larger at the instant the short-circuit occurs than it is a few cycles later. As the air-gap flux reduces because of limited field current capability, the stator current decreases. The internal voltage generated by the air-gap flux determines the magnitude of the short-circuit current. This changing air-gap flux accounts for the gradual decrease in the short-circuit current as shown in Figure 46.

The rate of decay and the steady-state fault current depend upon the synchronous machine time constants and the regulating action of the field current, if any. The initial current contribution is caused by an internal stator driving voltage generated by trapped rotor field flux. The current to the terminal short-circuit is limited by the internal impedance of the machine. The current in two or all three phases is asymmetrical at first, and consists of an ac and a dc component.

The ac component decays because the rotor flux is not maintained by the normal applied field voltage. The dc component, a transient not supported by any driving voltage, also decays. The initial frequency of the fault current is the same as system frequency and is directly related to rotor speed. Thereafter, the frequency of the fault current from a motor reduces at a rate dependent on motor mechanical load and combined motor and load inertia while those of a generator will increase based on the turbine power and combined turbine and generator inertia. For the first few cycles after the short-circuit, the frequency change is usually conservatively considered to be inconsequential.

The equivalent circuit used to represent a synchronous machine or a group of synchronous machines in simplified short-circuit calculations is shown in Figure 47. For calculations based on Thevenin's theorem, the equivalent circuit of the complete system containing several synchronous machines is reduced to a single driving voltage in series with an equivalent impedance.

As described previously, the synchronous machine driving voltages are not constant. They change with time depending on machine loading, excitation voltage, and system conditions. The machine impedances depend on the physical design of the machine and are essentially constant. They do change with temperature and frequency.

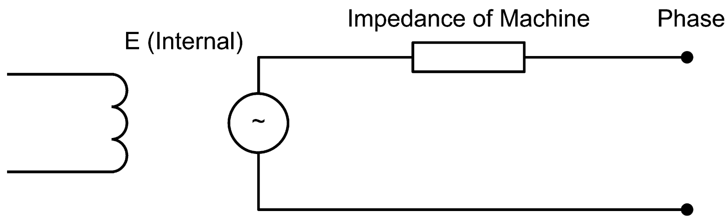



**Figure 47—Synchronous machine per phase equivalent circuit**

One simplified calculation technique of increasing the reactance from $X''_{\mathrm{dv}}$ in increments as time passes after the short-circuit is initiated accounts for the ac current decay, assuming the voltage is constant. This model obtains the machine decaying ac current contributions in the equivalent circuit without changing the circuit driving voltage. This technique is widely used and accepted by the industry. Typical reactance multiplying factors to be applied to $X''_{\mathrm{dv}}$ depend on whether the synchronous machine is a generator or a motor. Typical reactance multiplying factors are given in Table 5. Definitions of synchronous machine reactance are given in Clause 3 and reviewed in this subclause. The initial magnitude of the ac component is calculated using the subtransient reactance $X''_{\mathrm{dv}}$ of the machine. The initial magnitude of the dc component for short-circuit calculations is equal to the crest value of the initial ac component, assuming the fault current in one phase has the maximum possible asymmetry. Depending on the synchronous machine time constants, the transition of fault current from subtransient to transient to synchronous will vary and will generally take longer to decay than an induction motor current, as described in 7.3.3. If the field to the machine remains energized, then a steady-state fault current will exist due to continuous replenishing of stator flux energy that is removed by the fault. Otherwise, the fault current from a synchronous machine will decay to zero. Typical reactances of synchronous motors when the actual reactance is not available are given in Table 6.

**Table 5—Synchronous machine reactances and multiplying factors from IEEE Std C37.010 [B48] and IEEE Std C37.13™ [B51]**

| Type of machine | Medium-voltage and high-voltage per IEEE Std C37.010 | Low voltage per IEEE Std C37.13 |
|---|---|---|
| First-cycle calculations | | |
| Remote utility | $1.0 \times X_{\mathrm{s}}$ | $1.0 \times X_{\mathrm{s}}$ |
| Local generator | $1.0 \times X''_{\mathrm{dv}}$ | $1.0 \times X''_{\mathrm{dv}}$ |
| Synchronous motor | $1.0 \times X''_{\mathrm{dv}}$ | $1.0 \times X''_{\mathrm{dv}}$ |
| Interrupting-time calculations (1.5 to 4 cycles) | | |
| Remote utility | $1.0 \times X_{\mathrm{s}}$ | ∞ |
| Local generator | $1.0 \times X''_{\mathrm{dv}}$ | ∞ |
| Synchronous motor | $1.5 \times X''_{\mathrm{dv}}$ | ∞ |

[a] 1.5- to 4-cycle interrupting times do not apply to low-voltage circuit breakers.

**Table 6—Synchronous machine typical reactance**

| Number of poles | 60 Hz RPM | $X''_{dv}$ reactance |
|---|---|---|
| > 16 | ≤ 450 | 28% |
| 8 to 14 | 541 to 900 | 20% |
| 2 to 6 | > 1200 | 15% |

Most synchronous machines fall into one of the following three categories:

— Synchronous generators

— Synchronous condensers

— Synchronous motors

Synchronous generators are a principal source of electrical energy in power systems because almost all utilities use synchronous generators to generate electricity. Many of the larger industrial systems may include generators for energy conservation, such as in co-generation.

Synchronous condensers are used as a means of reducing power system transmission losses, reactive power control, and controlling voltages in a transmission or distribution system. They are connected to the power system as a motor, but are neither connected to a load nor to a prime mover. Modern equipment, such as static var compensators (SVCs), are much more common today than synchronous condensers, but the older rotating compensators may still be occasionally encountered in practice.

Synchronous motors are generally used to drive large loads, such as compressors, pumps, and M-G sets, and to supply capacitive power for power factor improvement. Sometimes synchronous motors are operated near unity power factor and rarely are operated drawing reactive power from system. The motors can have fixed or constant current fields, or can have regulators that control bus voltage or motor power factor.

### 7.3.3 Synchronous machine reactances

Synchronous machines have a number of reactances and time constants that can be used when modeling the machine. For short-circuit studies, these normally are reduced to the following:

— $X''_{d}$—Subtransient reactance (saturated)

— $T'_{dv}$—Transient reactance (saturated)

— $X_{d}$—Synchronous reactance (saturated)

— $X_{2v}$—Negative sequence reactance (saturated)

— $X_{0v}$—Zero sequence reactance (saturated)

— $T_{a3}$—Three-phase short-circuit armature time constant (saturated)

— $T''_{do}$, $T'_{do}$—Subtransient and transient time constants

The definitions are as follows:

a) Direct-axis saturated subtransient reactance ( $X''_{dv}$ ) is the apparent reactance of the stator winding at the instant short-circuit occurs with the machine at rated voltage, no load. This reactance determines the current flow during the first few cycles after short-circuit initiation.

b) Direct-axis saturated transient reactance ($X'_{\mathrm{dv}}$) is the apparent reactance of the stator winding several cycles after initiation of the fault with the machine at rated voltage, no load. The time period for which the reactance may be considered $X'_{\mathrm{dv}}$ can be up to a half second (1/2 s) or longer, depending upon the design of the machine, and is determined by the machine direct-axis transient time constant.

c) Direct-axis synchronous reactance $X_{\mathrm{d}}$ is the ratio of the fundamental-frequency component of reactive armature voltage ($V_{\mathrm{d}}$) to the fundamental-frequency direct-axis positive sequence component of armature current ($I_{\mathrm{1d}}$) under sustained balanced conditions with rated field current applied.

d) Negative sequence reactance is the apparent reactance determined by placing a line-to-line fault on the terminal of the generator at rated voltage. The negative sequence reactance is calculated knowing the direct-axis reactances by symmetrical components.

e) Zero sequence reactance is the apparent reactance determined by placing a line-to-ground fault on the terminal of the generator so that rated current flows. Tests are done at reduced voltage. The zero sequence reactance is calculated using the direct-axis and negative sequence reactances and symmetrical components.

f) Rated voltage three-phase short-circuit armature time constant is the time required for the ac three-phase short-circuit current (suddenly applied to the terminals of the machine initially at rated voltage, rated speed, and no load) to decay to 36.8% of its initial value. This time constant is a combination of the subtransient and transient short-circuit time constants.

g) Subtransient and transient short-circuit time constants are the times required for the respective components of subtransient and transient short-circuit currents to decay to 36.8% of their initial value.

The most important characteristics of synchronous machines when calculating short-circuit currents are the internal reactances and resistances. In practice, a single machine reactance is assumed to vary (with time) from a subtransient to a transient to a sustained or steady-state impedance; these variations control the ac component of the fault current. The resistance controls the dc rate of decay. The machine time constants that determine the rate of ac decay of the components of current are also important.

The appropriate means to determine the resistance to use for synchronous machines in short-circuit study representations is to apply the methodology given in Table 8 of IEEE Std C37.010. This requires the rated voltage values of the machine's negative sequence reactance and the three-phase short-circuit armature time constant, and the following equation:

$$\text{Effective resistance} = \frac{X_{2v}}{\left(2\times 3.14\times fT_{\mathrm{a3}}\right)}$$

This is particularly important if synchronous machines are applied local to the system being evaluated for short-circuit adequacy. If the per-phase stator resistance is used instead for the determination of *X/R*, this will result in an *X/R* ratio that is too low.

Expression of the synchronous machine variable reactance at any instant requires a complicated formula involving time as one of the variables. However, for the sake of simplicity, the reactance is considered fixed over the time interval for which the fault current is calculated. An expression of the ac rms current versus time for a three-phase short-circuit at the terminals of a synchronous machine is as follows in Equation (53):

$$I_{sc} = \left(\frac{E}{X''_{dv}} - \frac{E}{X'_{dv}}\right)e^{-\frac{t}{T_{do}''}} + \left(\frac{E}{X'_{dv}} - \frac{E}{X_{dv}}\right)e^{-\frac{t}{T_{do}'}} + \frac{E}{X_d} \tag{53}$$

where $t$ is in seconds and voltage and reactances are (typically) in per unit.

For a fault occurring away from the machine terminals, Equation (53) would have to include the transfer impedance between the machine and the fault. In addition, the resistance of the network would affect the decay time constants. Providing this detail in short-circuit calculations would be very burdensome, thus the desire for simplicity while maintaining conservatism.

## 7.4 Induction machines

### 7.4.1 Introduction

When induction motors are included in a system, the symmetrical ac component of the short-circuit current varies based on the time after the fault. In Clause 6, asymmetry was discussed and was shown to depend on the fault point *X/R* ratio and the point on the voltage sine wave at which the fault is initiated. A fault current flowing from energy sources may be asymmetrical and have both ac and dc components. The dc component is a transient value and decays with time. In Clause 9, several different theoretical and empirical equations were given that relate the maximum peak and rms currents in the first cycle to the ac symmetrical current.

The half-cycle short-circuit equation is:

$$I_{peak} = I_{ac,peak}\left(1+e^{-\frac{4\pi\tau R}{X}}\right) \tag{54}$$

$$I_{rms} = \sqrt{I_{ac,rms}^{2} + I_{dc}^{2}} = I_{ac,rms}\sqrt{\left(1+2e^{-\frac{4\pi\tau R}{X}}\right)} \tag{55}$$

where τ is equal to 0.5 cycle. IEEE Std 551™ has suggested a value of $\tau = 0.49 - 0.1\varepsilon^{-\frac{(X/R)}{3}}$.

Equation (55) can be rewritten to calculate the total current at other points in time.

$$I_{rms} = I_{ac,rms}\sqrt{\left(1+2e^{-\frac{4\pi tR}{X}}\right)} \tag{56}$$

where $t$ is in cycles at system frequency. Note that it may be difficult to obtain design data for induction machines to determine the machines' short-circuit impedance *X/R* ratios. This is particularly true during the preliminary stages of a project when circuit breakers or fuses are sized for short-circuit capability. Figure 4A-3 of IEEE Std 141-1993 is a good source of data to use for the *X/R* ratio of individually represented induction motors rated 50 HP and greater.

Equation (54) and Equation (55) can be used to calculate the maximum asymmetry during the first cycle, while Equation (56) can be used for interrupting times greater than 1 cycle.

Peak currents are often associated with equipment rated less than 1000 V, and rms currents are used with the higher voltage equipment. See Table 1 and Table 2 for the comparison of the approximation equation peaks to the actual peak. When equipment operating times are given in cycles at a particular frequency, the time frequencies can be ratioed to 60 Hz. Five cycles at 50 Hz is the same time as six cycles at 60 Hz.

The dc current decrement for a simple single circuit of one branch is an exponential decay. In a multi-branch power system, a single *X/R* ratio is only an approximation. Each branch will actually have its own time constant and the total current will decay at some rate that depends on the combined effect. There is no single-time constant that will exactly describe the dc decrement of a multi-branch total fault current.

### 7.4.2 Nature of induction motor contributions

A running induction motor that has a bolted three-phase short-circuit suddenly connected across its terminals will contribute currents to the short-circuit. Typical fault current versus time plots are shown in Figure 48. The plot shows a high initial current decay followed by fairly rapid decay to zero.

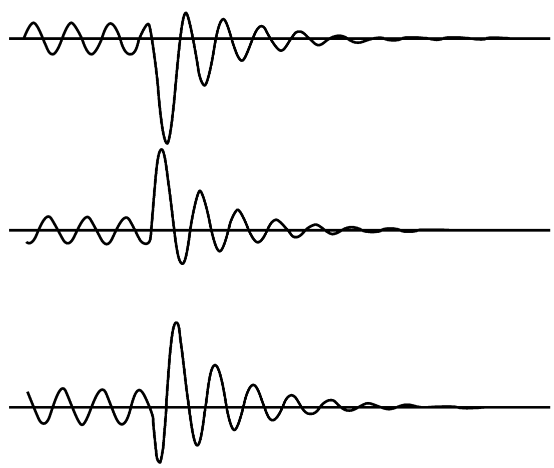


**Figure 48—Three-phase short-circuit currents from an induction motor (vertical axis represents Phase A, B, C currents; horizontal axis represents time)**

The current contribution is caused by a stator driving voltage generated by trapped rotor flux. The current to the terminal short-circuit is limited by the internal reactance of the motor. The current in two or all three phases is asymmetrical at first, and that each offset current consists of an ac and a dc component. The ac component decays because the rotor flux is not maintained by normal applied voltage. The dc component, a transient not supported by any driving voltage, also decays. The frequency differs initially from system frequency by motor slip and thereafter reduces at a rate dependent on motor mechanical load and combined motor and load inertia. For the first few cycles after the short-circuit, the frequency change is usually conservatively considered to be inconsequential.

The initial magnitude of the ac component is calculated using the subtransient motor reactance $X''$. It is accepted practice to substitute the known or estimated locked rotor reactance $X_{LR}$ for $X''$. The initial magnitude of dc component for short-circuit calculations is taken to be equal to the crest value of the initial ac component. This is based on the conservative assumption that the current in one of the phases will have the maximum possible asymmetry.

The equivalent circuit used to represent an induction motor or a group of induction motors with similar characteristics in simplified short-circuit calculations is shown in Figure 49. For calculations based on Thevenin's theorem, the equivalent circuit of the complete system uses a single induction motor reactance that represents motors of different decays. The individual induction motor voltage sources disappear by incorporation into the Thevenin equivalent single driving voltage. For a fault calculation involving different times after the fault, a different equivalent motor reactance would result because induction motor equivalent reactances vary considerably with the motor size and speed.

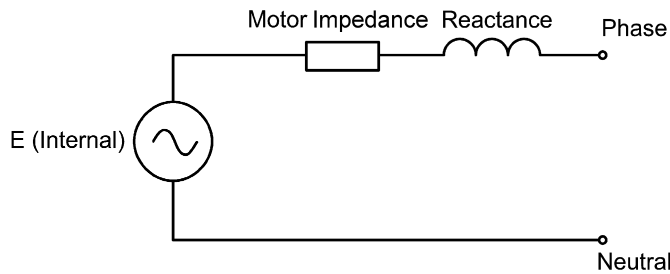



**Figure 49—Induction motor per phase equivalent circuit**

As indicated earlier, the ac component fault current from an induction motor will decay with time. A simplified calculation technique accounts for the ac component current decay by increasing the reactance from $X''$ in increments as time passes after the short-circuit starts. This approach has the advantage of obtaining the correct value of ac fault current while keeping the driving point voltage constant. Keeping the driving point voltage constant simplifies the calculation process by allowing complex power systems to be reduced to a simpler equivalent circuit. This technique is widely used and accepted by the industry. The multipliers used to increase the reactance depend on the induction motor horsepower, motor type, and speed. Table 8 provides the recommended multipliers.

Short-circuits are calculated frequently for fault points separated from contributing induction motor terminals by series impedances. For simplified calculations, the same reactance multiplying factors are applied to motor reactances whether the fault point is close to, or remote from, the motor terminals. This is ideal for simplifying short-circuit studies of large systems, usually performed by computer, because the set of equivalent circuit impedances does not change as the fault point is relocated to calculate duties for many buses.

In actual power systems, the voltage at a motor during a remote short-circuit may be partially sustained by nearer power sources. Initially, the voltage is depressed by the fault and the motor generates a short-circuit current contribution. During the fault, any partially sustained voltage, if high enough, returns the motor to normal motoring function at less-than-normal voltage. The simplified short-circuit calculation methods ignore this effect and assume that all connected medium and large size motors, no matter how remote, continue to contribute current to short-circuits for at least four cycles after the short-circuit starts. However, due to this network action and a higher total equivalent impedance between the remote motors and the fault, the remote motors contribution is less than it would be for a terminal fault.

The reactance multiplying factors that increase with time account for partial decay but possibly not complete disappearance of the motor contribution.

For longer times after the short-circuit, appreciably after four cycles, smaller induction motors are usually omitted from the equivalent circuit because induction motor fault current contribution decay is rapid and approaching zero, although the motors remain connected. In addition, some motors nearer the fault may have been disconnected by relays or contactor dropout on depressed voltage due to the nearby fault. The motor dropout effect could be included in interrupting-time calculations. However, for a conservative short-circuit current, often it is assumed that the motors do not drop out.

### 7.4.3 Large induction motors with prolonged contributions

When one or several large induction motors might appreciably affect the total short-circuit current at a given bus, better accuracy is obtained by calculating motor current at particular times of interest after the short-circuit starts (for example, at first-cycle and at contact-parting times for medium-voltage circuit breakers). ANSI-approved guides for ac medium-voltage circuit breakers suggest this in a note to the rotating machine reactance table.

Both ac and dc components of motor current ($I_{ac}$ and $I_{dc}$) are evaluated as time variables, assuming the decays from initial magnitudes are exponential, using Equation (57) and Equation (58):

$$I_{ac} = \left(\frac{E}{Z''}\right) e^{-\frac{2\pi t}{T''_{d}}} \tag{57}$$

and

$$I_{dc} = \sqrt{2}\left(\frac{E}{Z''}\right) e^{-\frac{2\pi t}{T_{a}}} \tag{58}$$

Time $t$ is in cycles at system frequency, and $T''_{d}$ and $T_a$ are the frequently used $X/R$ ratio time constants in radians at the same frequency. The time constant in radians for the ac component decay $T''_{d}$ is $X''/R_R$ where $R_R$ is the rotor resistance (perhaps modified slightly), and the time constant in radians for the dc component decay $T_a$ is $X''/R_S$ where $R_S$ is the stator resistance (again perhaps modified slightly).

The specified value of $T_a$ is the same as the $X/R$ ratio used in ANSI-approved standard calculations of short-circuit duties for ac high-voltage circuit breakers.

Note that the tangent of the locked rotor impedance angle is less than, and does not substitute for, the ANSI $X/R$ ratio. The locked rotor impedance has more resistance than the resistance used for short-circuit calculations. By definition, $R_S$ is the resistance determining the time constant of the dc component decay. Since the motor dc component currents are varying transiently, this is not the simple dc resistance that applies to the decaying dc currents, and the stator ac resistance is often used as a conservative approximation.

Many motor manufacturers are able to provide $T''_{d}$ and $T_a$ values for specific important motors, determined according to definitions in ANSI/NEMA MG 1-2003 [B5].

For more accurate calculations assuming exponential variations, moving the fault from the motor terminals to insert external impedance in series with the motor reactance affects both the short-circuit current initial magnitude and the time constants. For a series external impedance $Z_e = R_e + jX_e$, current magnitudes are found by substitution $(Z'' + Z_e)$ for $Z''$, the ac time constant $T_d$ becomes $(X'' + X_e)/R_R$, and the dc time constant becomes $(X'' + X_e)/(R_S + R_e)$.

When the external circuit from the motor to the fault is more complicated than a single impedance in series with the motor, calculations as just described are usually impractical and simplified calculations are normally used. The simplified calculations are, however, sometimes modified as suggested in ANSI-approved guides. For each large motor with a significant short-circuit contribution, and for each desired specific calculation time $t_s$ after the short-circuit starts, it is suggested that a special reactance multiplying factor be used in simplified calculations for the motor, instead of the standard factor listed in Table 7. The special reactance factor suggested is $\varepsilon^{+\frac{t_S}{t''_{d}}}$, with $t_s$ and $t''_{d}$ both in the same time units (same as the reciprocal of $\varepsilon^{-\frac{2\pi t_S}{T''_{d}}}$ used for current, with $t_s$ in cycles and $T''_{d}$ in radians, same frequency).

For a particularly important bus with large induction motors, combining simplified and more accurate procedures improves the quality of the results. With the motors omitted, the simplified calculation determines the contribution of the rest of the system to the bus short-circuit duty. The motor contribution is separately calculated by the more accurate procedure. Then the ac and dc components of the contributions are separately added and combined to obtain the final result.

### 7.4.4 Data accuracy

Data accuracy requirements are a function of motor size. The best possible data should be sought for larger motors that have the highest influence on short-circuit study results. For small motor groups, using first cycle $Z'' = 0.28$ per-unit impedance as typical is probably sufficiently conservative. Individual representation of large and medium motors (or separate groups of medium motors) is normally justified and using manufacturers' locked rotor current data when the actual short-circuit impedance is not known. Whenever it is possible to determine actual initial $Z''$ before applying multipliers increases confidence in calculation results. When induction motor contributions are especially important and the more accurate exponential calculation is justified, so is the collection of the best possible motor impedance and time constant data.

### 7.4.5 Details of induction motor contribution calculations according to ANSI-approved standard application guides

For application of ac medium-voltage circuit breakers, symmetrical (ac component) short-circuit current duties are calculated according to IEEE Std C37.010-1999 [B48], using the reactance multiplying factors of Table 7, column 2. The calculations omit all motors of less than 50 HP each.

For first-cycle (momentary) duties to be compared with closing and latching capabilities, subtransient reactance $X''$ of medium motors are multiplied by 1.2 to approximate a somewhat significant decay of the ac component during the first cycle of the short-circuit.

For large motors, the multiplier is 1.0, suggesting no appreciable decay. For symmetrical interrupting duty calculations, reactances of medium and large motors are multiplied, respectively, by 3.0 and 1.5, approximating a greater ac decay at ac medium-voltage circuit breaker minimum contact parting times of 1.5 to 4 cycles at 60 Hz. The pattern of approximation using these multipliers is illustrated by the solid lines of Figure 13.

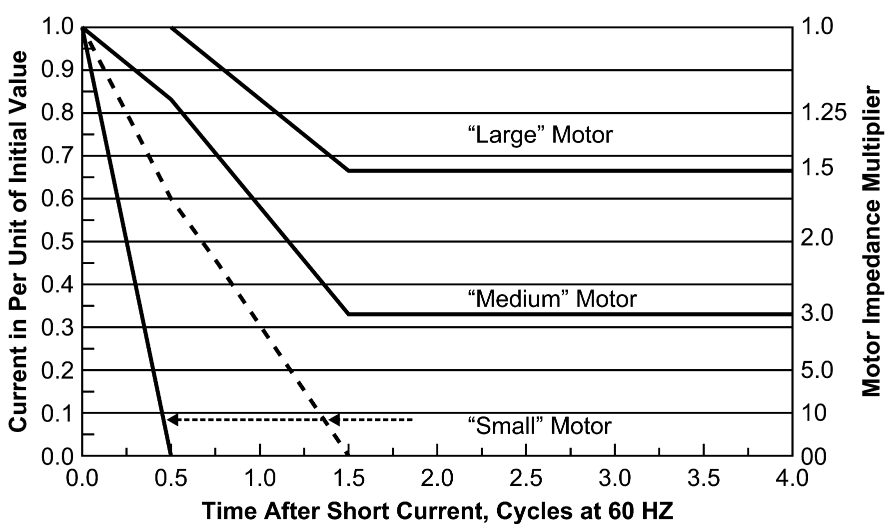



**Figure 50 —Symmetrical rms current contributed by an induction motor to a three-phase short-circuit at its terminals; solid lines according to IEEE Std C37.010-1999 [B48]; dotted line suggested by IEEE Std C37.13-1990 [B51]**

For application of ac low-voltage power circuit breakers and both medium and low-voltage fuses, only first-cycle calculations are necessary, and IEEE Std C37.13-1990 [B51] and IEEE Std C37.41™-2000 [B52] recommend representing all rotating machines in the equivalent circuit based on subtransient reactances, regardless of motor rated horsepower. IEEE Std C37.13-1990 [B51] qualifies this by suggesting

that motor short-circuit current contributions, for typical groups of low-voltage motors lacking detailed information, may be estimated at four times the summation of motor rated currents. A contribution of four times rated current corresponds to a first-cycle motor $Z = (V/4) = 0.25$ per unit based on motor rated apparent power (kVA) and voltage of 1 p.u. Usually exact motor short-circuit reactances are not readily available and is approximated by using 1/(locked rotor current).

The "four times rated current" approximate short-circuit contribution is determined by assuming a typical connected group having 75% induction motors at 3.6 times rated current and 25% synchronous motors at 4.8 times rated. Other "typical" group assumptions can be made; for example, many groups now have larger low-voltage induction motors instead of synchronous motors, but these larger motors also have higher and longer lasting short-circuit contributions. Accordingly, a "four times rated current" approximation continues to be accepted practice when all load is induction motors of unspecified sizes.

In general, 3.6, 4, or 4.8 times rated current is less than locked rotor current, so this approximation accounts for a sometimes appreciable reduction of ac motor contribution from the initial subtransient value (at $t = 0$) to the first-cycle value (evaluated at the half-cycle point) for a fault at the motor terminals. This reduction might be partly explained by the motor cables and/or overload heater impedances in series with low-voltage motors that are often omitted from the calculation, but a very important factor is the decay during the first cycle of motor current contribution due to collapsing motor flux.

### 7.4.6 Recommended practice based on ANSI-approved standards for representing induction motors in multi-voltage system studies

The differences in the two standards require two first-cycle calculations and an interrupting calculation. The ideal representation for multi-voltage systems is the simplest that determines with reasonable conservatism the influences of both low- and high-voltage induction motors on short-circuit duties for circuit breakers and fuses at both low and high voltages. A simple first-cycle network combining the two similar but different networks of IEEE Std C37.13-1990 [B51] and IEEE Std C37.010-1999 [B48] fits this ideal. The following interpretation and redefinition, based on extending existing similarities, resolves the differences and obtains a single network. Table 7 and Table 8 provide the multiplying factors and suggested motor reactances to be used when actual data are not available.

For a typical induction motor, the subtransient reactance of 16.7% is determined by the initial magnitude of symmetrical root-mean-square (rms) current contributed to a terminal short-circuit, assumed to be six times rated. Using a "4.8 times rated current" first-cycle estimate for larger size low-voltage induction motors, described as medium 50 HP, etc. in Table 7 and Table 8, is effectively the same as multiplying the subtransient reactance by approximately 1.2 (6.0/4.8 = 1.25). For this motor group, there is reasonable correspondence of low- and medium-voltage calculation procedures. For smaller induction motors, small below 50 HP in Table 7 and Table 8, a conservative estimate is the "3.6 times rated current" (equivalent of 0.28 per-unit reactance) first-cycle assumption of low-voltage standards, and this is effectively the same as multiplying 16.7% subtransient reactance by 1.67.

With this interpretation as a basis, the recommended small low-voltage induction motor representation is shown by Table 7, column 4, and by a dotted line on Figure 50. The entries for medium-size motors are the same as in Table 8 for medium-voltage calculations, and their use adds conservatism to low-voltage calculations when many induction motors are not small. The entries for small-size motors are essentially the same as in IEEE Std C37.13 [B51] for low-voltage calculations, and their use adds some conservatism to medium-voltage first-cycle calculations without changing interrupting duty calculations. Column 4 of Table 7 provides the recommended reactance multipliers that bridge the two ANSI-approved standards.

More high-efficiency motors are being used in industrial systems, which have higher locked-rotor currents and therefore lower subtransient reactances. Some engineering judgment must be used in the selection of assumed motor reactances based on the types of motors being used.

### Table 7—Induction motor reactance multiplying factor from IEEE Std C37.010 [B48] and IEEE Std C37.13 [B51]

| Type of machine | Medium voltage and high voltage per IEEE Std C37.10 | Low voltage per IEEE Std C37.13 | Recommended reactance multiplier |
|---|---|---|---|
| First-cycle calculations | | | |
| Large induction motors | 1.0 X″ | 1.66 X″ | 1.0 X″ |
| Above 1000 HP or | | | |
| Above 250 HP and 2 pole | | | |
| Medium induction motors | | | |
| 50 to 249 HP or | 1.2 X″ | 1.66 X″ | 1.2 X″ |
| 250 to 1000 HP, more than 2 pole | | | |
| Small induction motors | ∞ | 1.66 X″ | 1.66 X″ |
| Below 50 HP | | | |
| Interrupting-time calculations (three to five cycles) | | | |
| Large induction motors | | | |
| Above 1000 HP or | 1.5 X″ | Not applicable | 1.5 X″ |
| Above 250 HP and 2 pole | | | |
| Medium induction motors | | | |
| 50 to 249 HP or | 3.0 X″ | Not applicable | 3.0 X″ |
| 250 to 1000 HP, more than 2 pole | | | |
| Small induction motors | | | |

### Table 8—Suggested induction motor reactances from IEEE Std C37.010-1999 [B48] and IEEE Std C37.13-1990 [B51] using *X*″ = 16.7%[a]

| Type of machine | Medium voltage and high voltage per IEEE Std C37.10 | Low voltage per IEEE Std C37.13 | Recommended reactance |
|---|---|---|---|
| First-cycle calculations | | | |
| Large induction motors | | | |
| Above 1000 HP or | 16.7% | 27.8% | 16.7% |
| Above 250 HP and 2 pole | | | |
| Medium induction motors | | | |
| 50 to 249 HP or | 20.0% | 27.8% | 20.0% |
| 250 to 1000 HP, more than 2 pole | | | |
| Small induction motors | ∞ | 27.8% | 27.8% |
| Below 50 HP | | | |
| Interrupting-time calculations (three to five cycles) | | | |
| Large induction motors | | | |
| Above 1000 HP or | 25.0% | Not applicable | 25.0% |
| Above 250 HP and 2 pole | | | |
| Medium induction motors | | | |
| 50 to 249 HP or | 50.0% | Not applicable | 50.0% |
| 250 to 1000 HP, more than 2 pole | | | |
| Small induction motors | | | |
| Below 50 HP | ∞ | Not applicable | x |

[a] *X*lr can be used for *X*″

### 7.4.7 Motor resistance variation during short-circuit

Compared to induction motor reactance, resistance value plays less of a role in short-circuit current contribution. The *X/R* ratio of an induction motor normally has a value ranging from 1 to 100 and the value increases with size and voltage level. For a 100 HP, 0.46 V motor its *X/R* ratio is about 7, while a 1000 HP, 4 kV motor is about 25. A common practice in short-circuit calculation is to assume that the motor resistance value stays constant during short-circuit. However, as the abnormal short current flowing through motor windings, the temperature of winding will increase and so does the motor armature resistance. This effect of armature resistance change can be accounted for using the fixed *X/R* ratio approach, as described below.

**Fixed *X/R*—**Use the manufacture-provided machine *X/R* ratio (= $X''/R_a$) for both first-cycle and 1.5- to 4-cycle networks. The intention of this option is to account for the fact that the ANSI standard does not consider variable machine *X/R* ratio. When the *X/R* ratio is fixed, the motor resistance value for 1.5- to 4-cycle network is higher than that for the first cycle.

The following example shows $R_a$ calculations when *X/R* ratio is fixed:

| | **First-cycle network** | **1.5- to 4-cycle network** |
|---|---|---|
| Input: $X_{sc}$ | 15 | 25 |
| Input: $X/R = 10$ | | |
| Calculated: $R_a$ | 1.5 | 2.5 |

**Variable *X/R*—**The specified machine *X/R* ratio and subtransient reactance ($X''$) are used to calculate the armature resistance ($R_a$). This resistance is then used for both the first-cycle and 1.5- to 4-cycle networks. The motor reactance for the 1.5- to 4-cycle network is larger than the motor reactance for the first-cycle network. Therefore, this option results in a higher machine *X/R* ratio, a smaller resistance value, and a higher short-circuit contribution for the interrupting fault calculation of a high-voltage circuit breaker than the fixed *X/R* option.

The following example shows $R_a$ and *X/R* calculations when variable *X/R* is considered:

| | **First-cycle network** | **1.5- to 4-cycle network** |
|---|---|---|
| Input: $X_{sc}$ | 15 | 25 |
| Input: $X/R = 10$ | | |
| Calculated: $R_a$ | 1.5 | 1.5 |
| Final: *X/R* | 10 | 16.7 |

## 7.5 Transformers

### 7.5.1 Three-winding transformers

When a three-winding transformer forms part of the system under analysis, Figure 51 shows the equivalent circuit and the impedance expressions that are applicable. Note that equations shown in Equation (59) are not the same as the equations used for delta-star impedance conversions. Furthermore, Equation (59) applies only when all impedances are expressed on a common MVA base. This reflects the method used when the impedance tests are performed on the transformer. Once having made a T equivalent, the delta-star conversion can be used for delta impedance representation if desired.

The transformer impedance values are normally stated in percent and generally on the highest kVA winding base. The transformer nameplate will state that base is used for the impedances. Often when solving the conversion equations, one leg of the equivalent circuit will contain a negative impedance. The negative impedance must be retained to obtain the correct solution. However, it can be added to a series positive impedance if a computer program does not allow a negative impedance. Node D is an artificial point in the equivalent circuit and has no meaning in system evaluations.

The test data normally available for three-winding transformers includes winding-to-winding $I^2R$ load-loss data from which the resistances and reactances associated with the H-X, H-T, and X-T transformer windings can be derived. Separate resistance and reactance networks can then be developed and converted to wye networks in accordance with the equivalent circuit of Figure 51. The resistance network can then be combined with the reactance network for appropriate representation of a three-winding transformer's *X/R* ratios and impedances for use in short-circuit calculations.

$$
\begin{aligned}
X_a &= \frac{1}{2}\left(X_{HX} + X_{HT} - X_{XT}\right)\\
X_b &= \frac{1}{2}\left(X_{XT} + X_{XH} - X_{HT}\right)\\
X_c &= \frac{1}{2}\left(X_{HT} + X_{XT} - X_{HX}\right)
\end{aligned}
\qquad (59)
$$

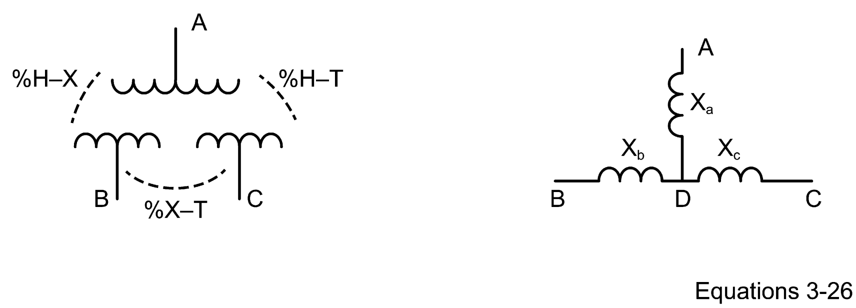



**Figure 51 —Equivalent circuit of a three-winding transformer**

## 7.6 Duplex reactor

A duplex reactor is a single reactor center tapped, or two reactors physically arranged, so that their magnetic fields are interlinked. With current flowing in one winding only, the reactor behaves the same as a single stand-alone reactor. Simultaneous currents flowing in each winding creates a different situation. The coupling factor, $f_c$, defines the linking of magnetic fields between the two windings. The flow of current in one winding will induce a voltage in the other winding (transformer action), that will in turn affect the other winding current flow. A positive coupling factor effectively increases the impedance between nodes A and B, while a negative coupling factor reduces the impedance. A reactor used to reduce fault current magnitudes will have a positive coupling factor. Table 9 provides representative coupling factors. For air-core reactors, while oil-immersed, gapped-iron-core (to avoid inductance changes due to core saturation) reactors may attain coupling factors that are greater. See Hamer [B14] for illustrations of duplex reactor application.

**Table 9—Representative coupling factors**

| | Coupling factor $f_c$ | |
|---|---|---|
| **Circuit voltage** | **Indoor or enclosed** | **Outdoor** |
| 0.00 kV to 5.0 kV | 0.4 to 0.5 | 0.3 to 0.4 |
| 5.1 kV to 8.7 kV | 0.3 to 0.4 | 0.2 to 0.3 |
| 8.8 kV to 15.0 kV | 0.2 to 0.2 | 0.2 to 0.3 |

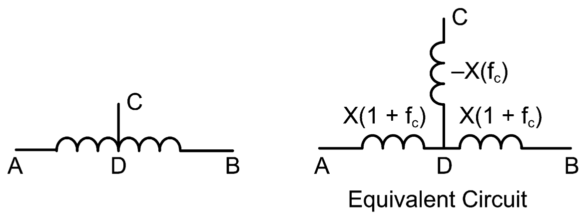



**Figure 52—Equivalent circuit of a duplex reactor**

## 7.7 Transmission lines and cables

### 7.7.1 Significant cable lengths

Cable impedance can have a significant effect on the short-circuit current in two ways. First, it reduces the magnitude of the symmetrical fault current. Second, because cables generally have low *X/R* ratios, the cable impedance helps lower the *X/R* ratio at the fault point. This reduces the total asymmetrical fault current because of a decrease in the dc component. The amount of cable length that should be included in a fault study depends of the system fault level, voltage level, and the accuracy of the results desired. Often cable lengths and configuration of multi-spaced conductors are estimated or neglected. Figure 54 provides a guideline of significant cable length if branch current flows will not be reduced by more than 5%. The chart is based on one 350 kcmil conductor per phase. The size of the conductor has a small effect. For conductor sizes ranging from 1/0 AWG to 2000 kcmil the change in significant cable length would be ± 15% of that shown in Figure 53 for a particular MVA source magnitude. Multiple cables per phase would increase the significant cable lengths by the number of conductors in parallel. Generally, cable lengths to motors are ignored. However, if there is a switching device at the motor, then the cable length may be important if the switch rating is less than the upstream switchgear rating.

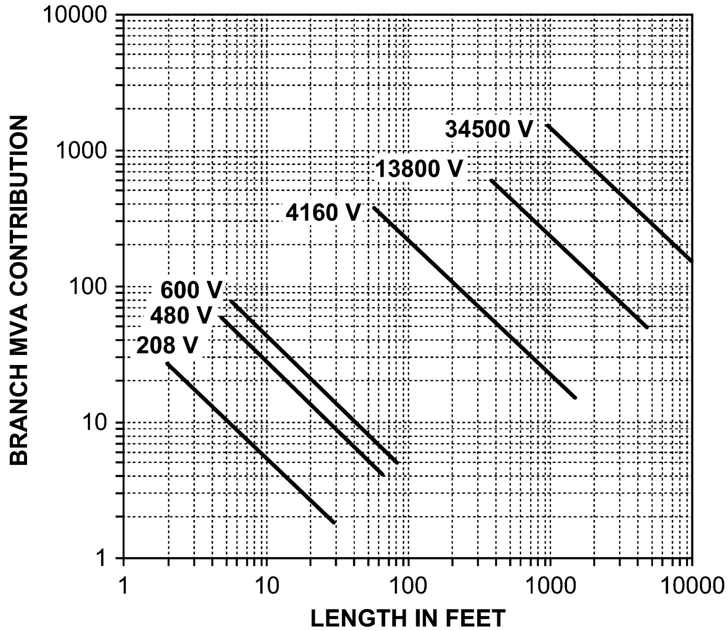



**Figure 53—Approximate cable lengths for a 5% change in fault current**

## 7.8 Capacitor and capacitive shunt components

When a system has capacitor or other capacitive shunt components, such as distributed susceptance of transmission lines and high-voltage cables, these capacitive components are periodically being charged and discharged. Under fault conditions, these shunt capacitive components also make short-circuit contributions to a fault, but decays at a very fast time scale. IEEE Std 551 [B41] contains a chapter on this topic with simulation results. Based on the simulation results, it cannot recommend that capacitors be added to system simulations for circuit breaker duty calculations. The existing ANSI C37 series fault calculation methodologies remain adequate for the determination of circuit breaker, fuse, and switch duties.

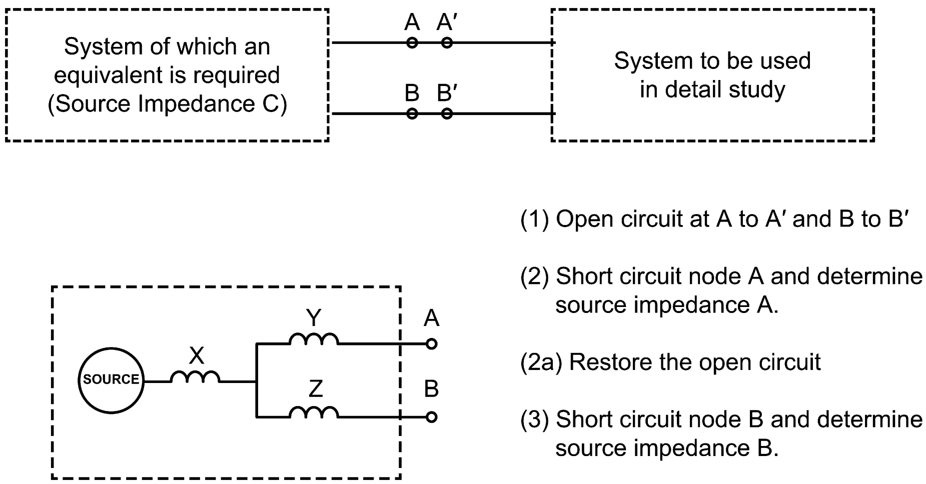
During fault conditions, the capacitor discharge takes place in the initial 1/30 to 1/8 cycles, depending on the time constant of the system. Since the circuit breaker protective device and contacts cannot operate in this time frame, the discharge takes place into closed contacts. The electromagnetically induced forces of the discharge current are instantaneously proportional to the current squared. Since the close and latch (momentary) rating of a circuit breaker is the maximum fundamental frequency rms fault current the circuit breaker can withstand, it can also be considered a measure of the forces which may be safely imposed on the various physical members of the circuit breaker during a rated frequency (i.e., 60 Hz) fault condition.

Based on the simulations shown in IEEE Std 551 [B41], capacitor discharge currents will have no effect on circuit breaker parting or clearing operations. Some small additional stresses may be imposed for the closing and latching duty for very large capacitor banks. However, it should be noted that the models developed in this clause were sized larger than standard design practices in order to avoid any potential problems.

However, when performing unbalanced short-circuit calculation, such as a line-to-ground fault calculations, these shunt branches provide a path for zero sequence fault current, especially for ungrounded systems. In this case, the zero sequence impedance for such shunt components should be included in the modeling for short-circuit calculations.

## 7.9 Equivalent circuits

It is sometimes desirable to make an equivalent circuit of a larger remotely connected system to reduce unnecessary detail in a portion of a system. These systems could have one or more connections to the system under study. A single-tie equivalent can be easily determined by the fault current flow from the remote system and its phase angle. A system with two or more non-independent connections requires more effort. Figure 54 shows the steps involved for a three-point "T" representation. A "pi" representation could also be used. The procedure is to make an equivalent network and determine an equivalent impedance value. For a two point equivalent, this requires solving for three unknowns by placing three separate faults on the system. The equivalent impedance determined from the equations could have two possible solutions. One answer may involve a negative impedance. While a negative impedance is a mathematically correct solution, it is not generally the answer used. The second solution has a positive impedance and is generally the impedance used.




From step 2, X + Y = Impedance A

From step 3, X + Y = Impedance B

From step 4, $X + \frac{Y * Z}{Y + Z}$ = Impedance C

Substituting and solving for X: $X = C \pm (C^2 + A*B - A*C - BC)^{1/2}$
with Y and Z solved from equations of steps 2 and 3.

**Figure 54 —T equivalent circuit**

A three-point equivalent requires solving six unknowns. The number of equations to be solved varies by the expression (points$^2$ + points)/2 and quickly becomes too cumbersome to do by hand. Some computer network analysis programs can perform this function. An alternate method is to work with the network to be reduced and to combine impedances by using series, parallel, and delta-star conversions until the desired nodes remain.

## 7.10 Zero sequence line representation

When unbalanced fault calculations are required involving cables or transmission lines that are mutually coupled in the zero sequence network, special handling of the circuits is required. Many computer-based programs can handle these types of circuits in any line combination. Coupled lines between the same two

buses are easily handled by changing the zero sequence impedance when one or two lines are in service. Lines that connect between different buses require a 1:1 ratio mutual-coupling transformer. The condition of the lines being common on one bus is a condition that can be handled by hand or in computer programs without zero sequence mutual coupling. It requires that the two line sections be handled as shown in Figure 55 and is similar to the duplex reactor previously shown in Figure 52.

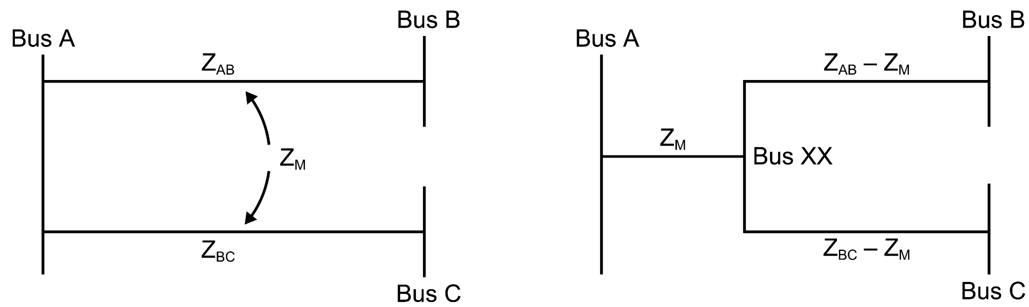



**Figure 55—Equivalent zero sequence mutual circuit**

# 8. Short-circuit calculation method and device duty per ANSI standards

## 8.1 Introduction

This clause outlines procedures for calculating short-circuit currents in three-phase ac systems according to the North American ANSI-approved standards, currently in effect. These procedures cover ac fault current decay from induction motors, synchronous motors, and synchronous generators and apply to low- and medium-voltage three-phase ac systems. Fault current dc decrement is also accounted for, in order to properly address the asymmetrical requirements of interrupting equipment.

Applicable ANSI-approved standards comprise the ANSI/IEEE Std C37.5 [B4] and IEEE Std C37-010 [B48] addressing fault current calculating procedures for medium- and high-voltage three-phase ac systems, IEEE Std C37.13™ addressing fault current calculating procedures for lower voltage ac systems, and the companion IEEE standards, IEEE Std 141, IEEE Std 241™, and IEEE Std 242™.

This clause focuses on calculating procedures yielding short-circuit currents for three-phase ac power systems in accordance with the above-mentioned guidelines, which are closely coupled to ANSI-related medium- and low-voltage interrupting equipment rating structures. Application and selection of interrupting equipment are covered in detail in Clause 10.

Emphasis is given to three-phase faults and only occasional reference will be made to single line-to-ground short-circuits.

## 8.2 Basic assumptions and system modeling

ANSI guidelines apply to low- and medium-voltage three-phase ac systems under the following assumptions:

— The ac system remains balanced and operates under constant frequency, which is the rated fundamental supply frequency.

— For the duration of the short-circuit, there is no change in the source driving voltage(s) that caused the initial short-circuit current to flow.

— Prefault load currents are neglected since they are assumed to be of much smaller magnitude than the short-circuit currents. As a consequence, prefault voltages, for fault current calculations purposes, are assumed to be the rated system voltages.

— Multi-voltage systems are assumed to be coherent voltage level-wise. In other words, the transformation ratios for all transformers are assumed to be 1.00, and the transformer rated voltages are assumed identical to the system rated voltages.

— The fault impedance is zero; therefore, it has no current-limiting effect.

— Contributions to the fault current from synchronous and induction motors vary in magnitude upon the inception of the short-circuit and cannot be considered negligible.

In view of the above-stated assumptions, quasi steady-state phasor analysis techniques, the utilization of a single driving voltage source at the fault point and the well-known computational framework of symmetrical components (Anderson [B2], Blackburn [B7], Stevenson [B60], Wagner and Evans [B62]) constitute the analytical framework within which ANSI-based short-circuit simulations are conducted. The analytical simplification of considering negative sequence impedances equal to positive sequence impedances is also adopted.

## 8.3 ANSI recommended practice for ac decrement modeling

### 8.3.1 General definitions and duty types

The term *ac decrement* reflects the natural tendency of short-circuit currents, contributed by rotating equipment, to decrease in magnitude upon the inception of the fault (Anderson [B2], Wagner and Evans [B63]). Synchronous machinery, as well as induction motors, exhibits the same qualitative behavior in the sense that their short-circuit currents decay with time from the onset of the short-circuit. For analytical convenience, the ANSI approved standards recognize three types of fault currents, associated with three distinct time periods.

a) The *first-cycle* currents, relevant up to and including one cycle immediately after the occurrence of the fault. These currents are deemed relevant for the so-called “first-cycle” duty, often referred to as *momentary* or *closing and latching* duty. These currents are assumed to feature no ac decrement at all.

b) The *interrupting* currents applicable to medium- and high-voltage circuit breaker parting times, relevant for the time period ranging from 1.5 to 4 cycles. These currents are deemed relevant for the so-called “interrupting” duty, also known as *breaking* duty. It is for these currents that ac decrement considerations become analytically relevant.

c) The *steady-state* short-circuit currents relevant to times well beyond the opening time of medium-voltage circuit breakers, even with intentional time delay, falling within the time window of 30 cycles and beyond from the moment of the fault inception. These currents are deemed relevant for the so-called “time-delayed” duty that is why these currents are often called *time-delayed* currents.

### 8.3.2 Induction motor ac decrement modeling

Detailed performance analysis of induction machinery in the time domain can be fairly involved and, in its general form, employs two-axis reactance theory similar to the one adopted for synchronous machinery analysis (Anderson [B2]). For simplified, quasi-steady-state–like short-circuit simulation purposes,

however, the conventional modeling framework of time varying impedances driven by a constant voltage is quite adequate.

For induction motors, the locked-rotor impedance can be used, instead of the subtransient impedance for first-cycle duty calculations. Calculations pertinent to the interrupting duty, accounting for ac decrement, use impedances higher than the locked-rotor impedance by applying multipliers, greater than unity, which are a function of machine type and size as portrayed in Table 10.

Differences between medium- and high-voltage (ANSI/IEEE Std C37.5, IEEE Std C37.010™) and low-voltage (IEEE Std C37.13™) standards require, strictly speaking, two first-cycle calculations and an interrupting calculation, as shown in the first two columns of Table 10. A convenient and desirable approach, however, for multi-voltage systems is one that determines with reasonable conservatism the influences of both low- and high-voltage induction and synchronous motors, using only one network for first-cycle current computations. A network combining the two similar, but different, networks of IEEE Std C37.13 and IEEE Std C37.010 is shown in the third column of Table 10 (Huening [B19]).

**Table 10 —Rotating equipment reactances per IEEE Std C37.010 and IEEE Std C37.13—Induction motor $X''$ = 16.7%**

| Source type | Medium- and high-voltage network IEEE Std C37-010 | Low-voltage network per IEEE Std C37.13 | Reactance for single multi-voltage system IEEE Std C37-010 and IEEE Std C37.13 |
|---|---|---|---|
| **Momentary or first-cycle calculations, 0 to 1 cycles** | | | |
| Utility | $X_s$ | $X_s$ | $X_s$ |
| **Synchronous machines** | | | |
| All turbo alternators, hydro with dampers, and synchronous condensers | $X''_d$ | $X''_d$ | $X''_d$ |
| Hydro without dampers | 0.75 $X''_d$ | 0.75 $X''_d$ | 0.75 $X''_d$ |
| **Synchronous motors** | $X''_d$ | $X''_d$ | $X''_d$ |
| **Large induction motors** | | | |
| Above 1000 HP | $X''$ | $X''$ | $X''$ |
| Above 250 HP, 3600 r/min | $X''$ | $X''$ | $X''$ |
| **Medium induction motors** | | | |
| All others, 50 HP and above | 1.2 $X''$ | 1.2 $X''$ | 1.2 $X''$(see note 1) |
| **Small induction motors** | | | |
| All smaller than 50 HP | ∞ | $X''$ | 1.67 $X''$(see note 2) |
| **Interrupting-time calculations, 1.5 to 5 cycles** | | | |
| Utility | $X_s$ | Not applicable | $X_s$ |
| **Synchronous machines** | | | |
| All turbo alternators, hydro with dampers, and synchronous condensers | $X''_d$ | Not applicable | $X''_d$ |
| Hydro without dampers | 0.75 $X''_d$ | Not applicable | |
| **Synchronous motor** | 1.5 $X''_d$ | Not applicable | 1.5 $X''_d$ |
| **Large induction motors** | | | |
| Above 1000 HP | 1.5 $X''$ | Not applicable | 1.5 $X''$(see note 3) |
| Above 250 HP, 3600 r/min | 1.5 $X''$ | Not applicable | 1.5 $X''$(see note 3) |
| **Medium induction motors** | | | |
| All others 50 HP and above | 3.0 $X''$ | Not applicable | 3.0 $X''$ |
| **Small induction motors** | | | |
| All smaller than 50 HP | ∞ | Not applicable | ∞ |

NOTE 1—For larger size low-voltage induction motors, described as medium, above 50 HP, etc. using a contribution of 4.8 times rated current, attributed in IEEE Std C37.13 to synchronous motors and considered also applicable to these induction motors, determines a 20.8% reactance. This is effectively the same as multiplying the 16.7% assumed reactance by approximately 1.2 as shown in the second column of Table 10. For this motor group, therefore, there is reasonable correspondence of low- and medium-voltage procedures.

NOTE 2—For a typical induction motor, the subtransient reactance of 16.7% is determined by the initial magnitude of symmetrical root-mean-square (rms) current contributed to a terminal short-circuit, assumed to contribute six times rated current. For smaller induction motors, small, below 50 HP per Table 10, a conservative fault current estimate, according to IEEE Std C37.13 is 3.6 times rated current (equivalent of 0.278 per-unit reactance). This is effectively the same as multiplying the 16.7% subtransient reactance by 1.67 as shown in the third column of Table 10.

NOTE 3—Large induction motors (Above 1000 HP, 4 poles or more and above 250 HP, 2 poles) are assumed to contribute six times their rated current to a terminal short-circuit, when better data are not available. The corresponding 16.7% reactance is modified, per Table 10, depending on the calculation time. The same multipliers, however, apply if motor reactance data are known. For example, a 500 HP, 900-r/min motor with a known locked-rotor reactance of 15% would have a first-cycle reactance of 18% or an interrupting-time reactance 45%, (three times 15%).

Using the approach of a single multi-voltage level network, as outlined in Table 10, first-cycle duty calculations for circuit breakers and fuses at both low and high voltages can be made with one set of network impedances.

It is important to emphasize at this point that accurate induction motor data for short-circuit are paramount for simulation accuracy, particularly for industrial systems featuring a large content of induction motor loads. Motor data accuracy requirements are, as a rule, a function of the motor size. The best possible data should be sought for larger motors which also have the highest influence on calculated short-circuit duties. For small motor groups using first-cycle reactance of 28% (0.28 p.u.) as typical is probably sufficiently conservative. Individual representation of large and medium motors (or separate groups of medium motors) is normally justified and increases confidence in the obtained results. It is recommended to consult the manufacturer for accurate locked-rotor current data (or first-cycle reactances), whenever possible, to properly establish first-cycle impedances before applying the impedance correction multipliers shown in Table 10 for interrupting duty simulations. For the cases in which induction motor contributions are critically important, additional data pertinent to motor time constants reflecting more exactly ac decrement characteristics for every machine may be justified. Higher-efficiency motors also feature higher locked-rotor currents and therefore lower first-cycle reactances. In the absence of exact data, informed engineering judgement must be used during the selection of assumed motor reactances, depending on the array of the induction motors present. Typical data for induction motor impedances as well as associated *X/R* ratios for short-circuit analysis can be found in IEEE Std 141.

### 8.3.3 Synchronous generator ac decrement modeling

Detailed analysis of synchronous machinery in the time domain requires machine reactances of the direct and quadrature axis (assuming the popular computational framework of two-axis reactance theory is used) as well as several time constants to properly reflect the necessary field and stator dynamics (Anderson [B2]). For simplified short-circuit simulation purposes, under the already assumed computational and modeling framework, the phenomenon of ac decrement can be conveniently modeled using time varying impedances driven by a constant field voltage.

ANSI/IEEE Std C37.5 and IEEE Std C37.010 stipulate that direct-axis reactances are sufficient for synchronous machines and rest on the utilization of the saturated subtransient and transient reactances. The subtransient impedances are primarily used for the first-cycle calculation and are the basis for subsequent interrupting duty calculations.

Table 10 suggests no adjustment for the synchronous generator impedances for the interrupting calculations. This is deliberate because ac decrement for generators is accounted for in conjunction with dc decrement, as indicated in 8.5. Generator ac decrement modeling remains, however, conditional on the proximity of the generator to the fault. If a generator is electrically close to the short-circuit location its contribution is considered of the local type. If not, its contribution, and the generator, is considered as remote.

The criterion according to which synchronous generator contributions are classified as *local* or *remote* consists in comparing the magnitude of the actual generator contribution $I_g$, with the generator contribution $I_t$ for a hypothetical three-phase fault at its terminals. If the ratio $I_g/I_t$ is greater or equal to 0.4, the generator at hand is considered to be local with respect to the particular fault location. If this is not the case, the generator is classified as remote for the given fault location.

The same criterion can, equivalently, be quantified in terms of the generator subtransient impedance $X''_d$, as compared to the equivalent external impedance, $Z_{ext}$. According to this formulation, the generator contribution is considered remote if the ratio ($Z_{ext}/ X''_d$) equals or exceeds 1.5, assuming both impedances are expressed on the same MVA basis. Care, however, needs to be exercised in calculating $Z_{ext}$ for non-radial systems.

## 8.4 ANSI practice for dc decrement modeling

### 8.4.1 Introduction

Accounting for fault current asymmetry requires proper consideration for the unidirectional fault current component of the short-circuit current. This unidirectional fault current component, often referred to as *dc-offset*, is due to the fact that current interruption in any inductive circuit cannot be instantaneous. The physics of inductive current interruption (Wagner and Evans [B62]) dictates that, in general, a unidirectional current is present that decays exponentially with time upon the onset of the short-circuit. The rate of decay of the dc-offset is closely related to the reactances and resistances of the supply system, while its initial value solely depends on the exact moment of interruption. The total asymmetrical fault current whether quantified as first-cycle currents immediately after the fault, or as interrupting fault currents sensed by a circuit breaker at contact separation, is directly dependent on the magnitude of this dc-offset and is instrumental in determining the electrical and mechanical capabilities of interrupting equipment for any voltage rating.

For multi-machine systems of general configuration, more than one source contributes to the fault current through paths that depend on their location with respect to the fault position. Strictly speaking, therefore, the dc decrement characteristics of the fault currents are influenced by more than one *X/R* ratio. ANSI guidelines stipulate that, for computational convenience, system dc decrement characteristics can be safely quantified by a single *X/R* ratio, the *X/R* ratio at the fault position. This *X/R* ratio is to be calculated as the ratio of the equivalent system reactance with all resistances neglected, to the equivalent system resistance with all reactances neglected, both quantities calculated at the fault position. In other words, the equivalent system reactance seen from the fault location is to be calculated with a strictly reactive network and the equivalent system resistance is to be calculated with a strictly resistive network. It is for this reason that this technique is often referred to as the "separate *X* and *R* reduction" technique.

Note that it is also acceptable, per IEEE Std C37.010, to use the magnitude of the total complex equivalent impedance, *Z,* instead of the total equivalent reactance at the fault point. The equivalent resistance, however, still needs to be obtained using a separate reduction of the resistive network. This is often referred to as the *Z/R* approach. The *Z/R* technique can be applied only if the same complex impedance used to calculate the *X/R* ratio was also used to calculate the fault current.

The *X/R* ratio calculated with the separate *X* and *R* reduction is not necessarily the same as the ratio of the imaginary to the real part of the complex network impedance at the fault point calculated using complex arithmetic. In general, the *X/R* ratio resulting from the separate *X* and *R* technique will be of higher magnitude, thus yielding a certain degree of conservatism.

ANSI first-cycle fault currents, whether quantified in terms of total asymmetrical rms or peak amperes, directly depend on the fault point *X/R* ratio as determined from the first-cycle network using either one of the above-stated techniques.

Similarly, interrupting currents calculated using procedures given in ANSI-approved standards, applicable to medium- and high-voltage circuit breakers, are quantified in terms of asymmetrical rms amperes and depend on the fault point *X/R* ratio, which now must be calculated from the interrupting network, using the interrupting network equipment impedances, according to Table 10. Furthermore, these interrupting currents are also very much dependent on the circuit breaker structure. More specifically, ANSI-approved standards distinguish between circuit breakers rated on a total current basis, hereby referred to as *totally* rated circuit breakers covered in ANSI/IEEE Std C37.5 and circuit breakers rated on a symmetrical current basis, covered in IEEE Std C37.010, hereby referred to as *symmetrically* rated circuit breakers.

Both rating structures, total and symmetrical, recognize the notion of local and remote sources of fault currents, with respect to the actual fault position. Local contributions reflect generating station contributions and are recognized according to the criterion stipulated in 8.4.

Both rating structures recommend applying multipliers to the symmetrical currents supplied by either source type to arrive at asymmetrical current estimates. Different multipliers are to be applied to the currents contributed from "local" sources as compared to the ones contributed by "remote" sources. These multipliers are a function of the rating structure, of the system *X/R* ratio, of the circuit breaker interrupting speed, as well as of the parting time. There is, however, one important difference. Interrupting fault currents calculated for totally rated circuit breakers are actual short-circuit currents, while interrupting currents calculated for symmetrically rated circuit breakers are currents that are only to be compared with the symmetrical interrupting capabilities of these circuit breakers.

The multipliers suggested by the so-called "remote" curves are higher in magnitude as compared to the ones suggested by the so-called "local" curves, because generator ac decrement is accounted for in the latter. In order, therefore, to avoid overestimating the magnitude of the asymmetrical fault current, by simply applying only the remote multiplier, it is recommended to consider a weighted-average between the local and the remote contents of the symmetrical fault current. The multiplier suggested by the local curves is applied to the local content of the symmetrical current, while the remote multiplier is applied to the remote content, using the same fault point *X/R* ratio.

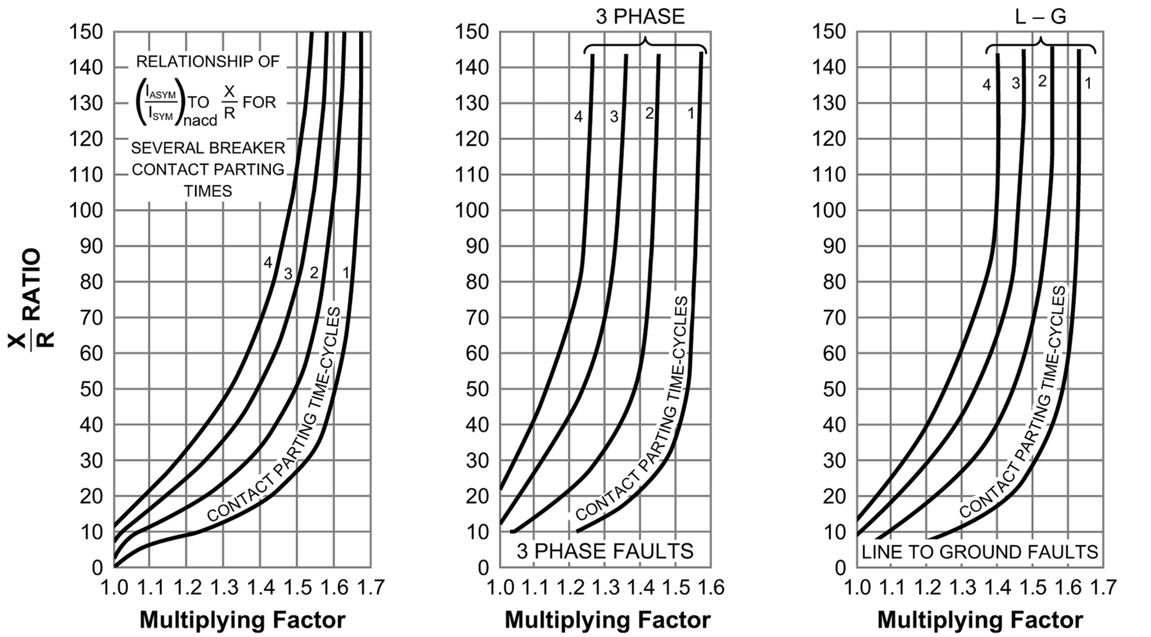
An alternative calculation, known as the *no ac delay (NACD) ratio*, yields identical results and consists in applying a single composite multiplier to the symmetrical fault current magnitude. The NACD ratio is quantified as the remote content of the symmetrical fault current, expressed in per unit of the total symmetrical fault current. The multiplier to be applied to the total symmetrical fault current is calculated as follows:

a) Determine the local and remote multiplying factors once the circuit breaker rating structure, contact paring time, and fault point *X/R* ratio are known.
b) Take the difference between remote and local multiplying factors.
c) Multiply this difference by the NACD ratio.
d) Add the above-calculated value to local multiplying factor.
e) If the resulting factor turns out to be less than 1.0, use 1.0.

Induction motor contributions can be considered as local for the purposes of this calculation, since enough conservatism is already embedded in the local decrement curves.

### 8.4.2 DC decrement curves for totally rated circuit breakers

The application of circuit breakers of this rating structure is described in ANSI/IEEE Std C37.5 and reflects an earlier circuit breaker rating structure. When calculating interrupting currents conforming to this circuit breaker rating structure, dc decrement is quantified by applying a local multiplier to the local content of the symmetrical fault current and a remote multiplier to the remote content of the symmetrical short-circuit current. These multipliers are a function of the fault point *X/R* ratio and the circuit breaker contact-parting time and can be obtained from the curves illustrated in Figure 56. Figure 56(a) depicts the remote multipliers as a function of the fault-point *X/R* ratio and is applicable to both three-phase and line-to-ground faults. Figure 56(b) and Figure 56(c) depict the local multipliers for three-phase and line-to-ground faults respectively.




9-1a REMOTE Multiplying Factors for Three-Phase and Line-to-Ground Faults Remote from Generators. Includes only dc Components.

9-1b LOCAL Multiplying Factors for Three-Phase Faults Predominantly Fed from Generators. Includes ac and dc decay Components.

9-1c LOCAL Multiplying Factors for Line-to-Ground Faults Predominantly Fed from Generators. Includes ac and dc decay Components.

**Figure 56—Multiplying factors for circuit breakers rated on a total current basis**

The curves are parameterized in terms of circuit breaker contact-parting time, but they can also be used in terms of circuit breaker interrupting speed bearing in mind that, generally, a three-cycle interrupting-time circuit breaker has a two-cycle minimum contact parting time, a five-cycle interrupting-time circuit breaker has a three-cycle minimum contact parting time, and a eight-cycle interrupting-time circuit breaker has a four-cycle minimum contact parting time.

The multipliers described by the remote curves can be calculated analytically. Since this multiplier is the ratio of asymmetrical to symmetrical rms fault current, Equation (60) applies.

$$I_{asym} / I_{sym} = \sqrt{(1+2e^{-4\pi C/(X/R)})} \tag{60}$$

where

- $C$ is the circuit breaker contact parting time in cycles at 60 Hz
- $X/R$ is the system fault point $X/R$ ratio at the same frequency

No similar set of equations describes the “local” multipliers analytically, depicted in Figure 56(b) and Figure 56(c). These multipliers must, therefore, be obtained directly from the curves; they can be estimated from points on the curves, or by curve-fitting equations.

It is seen that different multipliers for the same *X/R* ratio are suggested depending on whether the fault contribution comes from a local or remote source for the case of three-phase faults. The same applies for line-to-ground faults. Both fault types, however, share the same curves for remote sources. It is by virtue of the local curves that proper account is given to generator ac decrement, a factor that is not taken into account in the interrupting network (see also Table 10).

If the short-circuit is predominantly fed from remote sources, the remote multiplier can be used for a conservative estimate. If the short-circuit current consists entirely of contributions from local sources, the local multiplier can be used instead. For fault currents exhibiting a hybrid extraction of both local and remote contributions, the weighted average of local and remote contents can be used as described above.

### 8.4.3 DC decrement applied to symmetrically rated circuit breakers

The application of circuit breakers following this rating structure is described in IEEE Std C37.010 and reflects a more recent rating structure. When calculating interrupting currents conforming to this circuit breaker rating structure, accounting for dc decrement is also quantified by applying a local multiplier to the local fault current content and a remote multiplier to the remote fault current content of the symmetrical short-circuit current. These multipliers are, again, tabulated as a function of the fault point *X/R* ratio and the circuit breaker contact parting time, and are shown in the curves illustrated in Figure 57, Figure 58, and Figure 59.

Figure 57 depicts the remote multiplying factors and applies to both three-phase and line-to-ground faults. It is emphasized that it accounts solely for dc decrement. Different curves are given for various circuit breaker speeds and each speed contains curves for various parting times.

Figure 58 and Figure 59 depict local multiplying factors for three-phase and line-to-ground faults respectively. They include the effects of both ac and dc decrement. Different curves are also given here for various circuit breaker speeds and each speed contains curves for various parting times.

It is seen that these sets of curves contain more curves for explicit tabulation of intentional time delay for relatively higher circuit breaker contact-parting times. Different multipliers, for the same *X/R* ratio, are also suggested for this rating structure depending on whether the fault contribution comes from a local or remote source for the case of three-phase faults or line-to-ground faults. It is by virtue of the difference in these curves that proper account is given to generator ac decrement, decrement that is not taken into account in the interrupting network (see also Table 10).

Note that systems with large local generators, particularly for those that are close-coupled to switchgear (e.g., offshore platforms), it is possible that the short-circuit-impedance *X/R* ratio could approach 100. Special application considerations, including circuit breaker interrupting or breaking current derating, may apply.

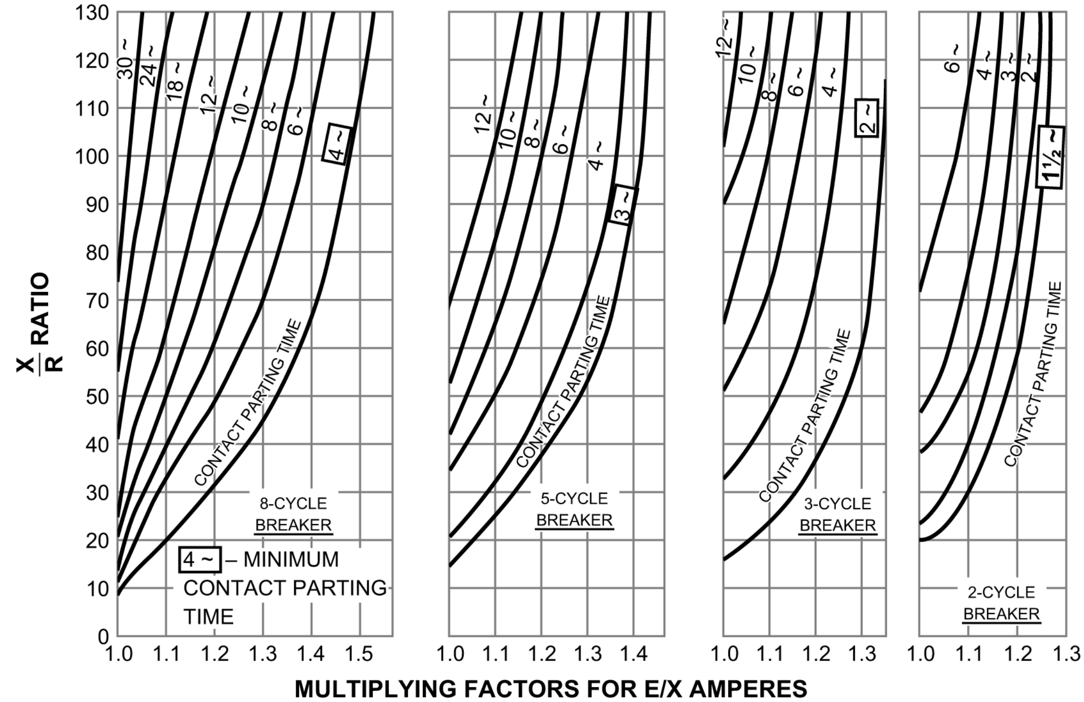



**Figure 57 —Remote multiplying factors for symmetrically rated circuit breakers; three-phase and line-to-ground faults; includes only dc decay component**

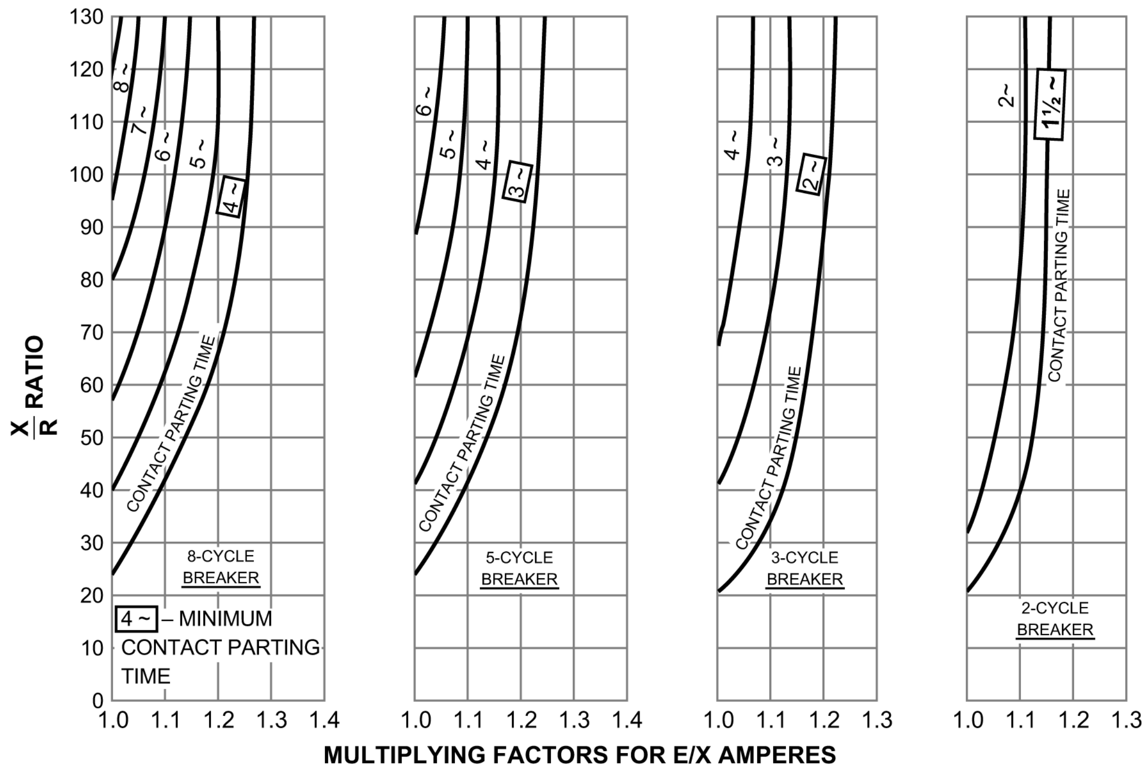



**Figure 58 —Local multiplying factors for symmetrically rated circuit breakers; three-phase faults predominantly fed from generators; includes ac and dc decay components**

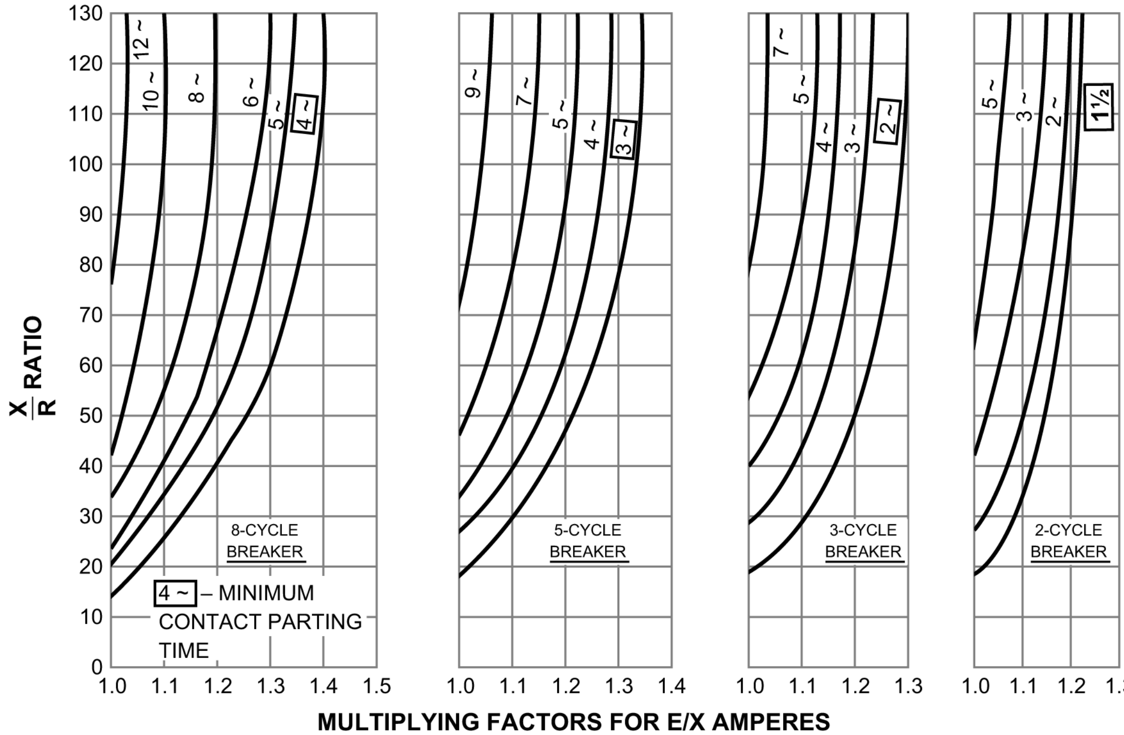



**Figure 59 —Local multiplying factors for symmetrically rated circuit breakers; line-to-ground faults predominantly fed from generators; includes ac and dc decay components**

If the short-circuit current is predominantly fed from remote sources, the remote multiplier can be used for a conservative estimate. If the fault current is solely contributed by local sources, the local multiplier alone can be used instead. For fault currents exhibiting a hybrid extraction of both local and remote contributions, the weighted average of local and remote contents can be used as described in 8.4.

The difference between the rating structure of symmetrically versus totally rated circuit breakers is that, per IEEE Std C37.010, the former have an embedded asymmetry factor, which quantifies the dc component of the short-circuit current at contact parting time, in terms of the total rms fault current, as follows in Equation (61).

$$I_{\text{Total rms}} = I_{sym}\sqrt{1+I_{\text{dc}}^{\;2}} \tag{61}$$

with $I_{dc}$ expressed in per unit of the symmetrical rms fault current, $I_{sym}$, at contact parting time. IEEE Std C37.010 assumes that a short-circuit on any ac system can produce the maximum offset (dc component) of the current wave and quantifies this embedded asymmetry for the symmetrically rated breakers based on a dc component decay time constant of 45 ms. This corresponds to an *X/R* ratio of about 17 for 60 Hz systems or about 14 for 50 Hz systems.

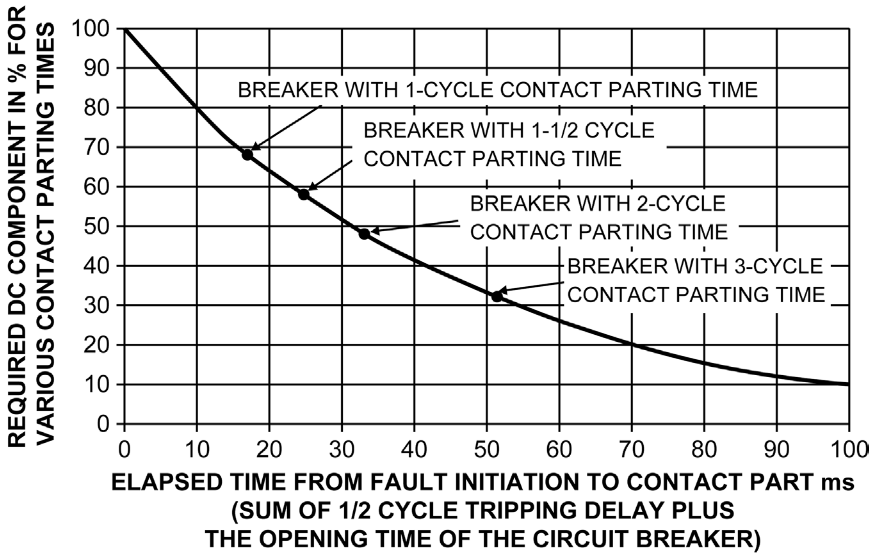



**Figure 60 —Power circuit breaker design requirements**

Analytically, the dc component decay rate is given by the time constant, as the circuit *L/R* in seconds given by Equation (62).

$$T_{dc} = \frac{(\text{Circuit } X / R)}{2\pi f \ (\text{Hz})} \tag{62}$$

Therefore, the required dc component in % of ac component = $e^{-c/T_{dc}} \times 100$, where $c$ is the contact parting time expressed in ms. The dc component of the fault current is shown in Equation (63).

$$I_{dc} = [\%dc] X \sqrt{2} I_{sym} \tag{63}$$

These facts are also reflected in the differences between the magnitudes of multipliers used for totally or symmetrically rated circuit breaker. In fact, multipliers obtained through Figure 57, Figure 58, and Figure 59 are, for similar circuit breaker speeds and parting times, the multipliers one would obtain from Figure 56 after dividing them by the above-defined asymmetry factor.

It should be kept in mind that, notwithstanding the assumption of an *X/R* ratio equal to 17, a minimum relay time of 0.5 cycles is also assumed. According to IEEE Std C37.010, relaying times less than 0.5 cycles, excessive fault current motor contribution content, fault current delayed current zero crossings, and/or dc time constants exceeding 120 ms for 60 Hz systems (*X/R* ratios higher than 45), require special considerations and/or consultation with the manufacturer.

When following the above calculation procedures, the calculated interrupting asymmetrical short-circuit currents can be directly compared with the interrupting capabilities of symmetrically rated circuit breakers. This convenience is, however, the reason that asymmetrical currents calculated using the so-called symmetrical sets of curves of this section do not reflect the true value of the total asymmetrical fault current.

## 8.5 ANSI-conformable fault calculations

### 8.5.1 Introduction

One first-cycle calculation and one interrupting calculation are, in general, necessary, for the purposes of applying and sizing fault interrupting devices, according to ANSI approved standards. Both calculations are to be performed on the same system single-line diagram. First-cycle calculations are applicable to both low- and medium- to high-voltage systems while interrupting calculations are only applicable to medium- and high-voltage systems and are closely related to circuit breaker rating structure.

Occasionally, a third calculation needs to be performed—the so-called "time-delayed" calculation. This type of analysis intends to assess fault currents within the time window that extends beyond six cycles from the fault inception and relates to current levels sensed by time-delayed relaying devices.

The necessary steps that need to be followed whenever ANSI-conformable short-circuit studies are to be undertaken are summarized in 8.5.3.

### 8.5.2 First-cycle calculations

The first-cycle calculations are as follows:

a) For momentary (first cycle) fault currents construct the first-cycle network using source impedances per Table 10.

b) Reduce the network impedances, at the fault position, to a single *R* and then to a single *X*, using separate *R* and *X* network reductions respectively and calculate the fault point *X/R* ratio. An alternative option is to obtain the network equivalent resistance *R* from a separate *R* reduction and use the magnitude of the complex network impedance *Z* at the fault point, as resulted from complex network reduction, instead of using *X*. This method, also known as the *Z/R method*, can be used provided the fault current was also calculated from the same network complex impedance *Z*. It is also permissible to consider as the fault-point prefault driving voltage, the exploitation (operating) voltage anticipated under actual service conditions, which could exceed the customarily assumed 1.00 p.u.

c) Calculate the symmetrical fault current by considering the equivalent impedance at the fault point to be the complex impedance *Z*, with real and imaginary parts *R* and *X* calculated from the separate reductions, *or* by using the magnitude of the equivalent complex network impedance *Z* at the fault point, as resulted from complex network reduction.

d) Use either *R* and *X* or *Z* and *R* to calculate the total asymmetrical rms and/or peak currents at the fault location.

First-cycle peak currents—used for verifying circuit breakers (high and low-voltage) and fuse capabilities—can be calculated using the IEEE Std 551 equation, as follows:

$$I_{peak} = \sqrt{2} I_{Sym} (1 + e^{-2\pi\tau/(X/R)}) \tag{64}$$

where

$\tau$ is $0.49 - 0.1e^{-(X/R)/3}$

Often, a peak multiplier of 2.6 is also used for simplicity when calculating duties of medium- and high-voltage circuit breakers above 1 kV. Note that the recommended 2.6 peak factor assumes an *X/R* ratio of 17 and higher multipliers may result when larger *X/R* ratios are encountered.

First-cycle asymmetrical rms short-circuit currents used for applying older high-voltage circuit breakers can be calculated using the ANSI equation, as follows:

$$I_{asym} = I_{sym}\sqrt{1+2e^{-2\pi/(X/R)}} \tag{65}$$

The above-depicted equation, essentially, calculates total asymmetrical rms currents at half-cycle. Often a multiplier of 1.6 is also used for simplicity when calculating duties of medium- and high-voltage circuit breakers above 1 kV. The recommended 1.6 asymmetrical multiplier, whenever used, implicitly assumes a fault point *X/R* ratio of 25. Again, higher *X/R* ratios may yield a multiplier higher than 1.6.

### 8.5.3 Interrupting calculations

The steps for interrupting calculations are as follows:

a) For interrupting (1.5 to 5 cycles) fault currents construct the interrupting network using source impedances per Table 10.

b) Reduce the network impedances, at the fault position, to a single *R* and then to a single *X*, using separate *R* and *X* network reductions respectively and calculate the fault point *X/R* ratio. An alternative option is to obtain the network equivalent resistance *R* and then use the magnitude of the complex network impedance *Z* at the fault point, as resulted from complex network reduction, instead of using *X*. This is the so-called "*Z/R* method."

c) Calculate the symmetrical interrupting currents using a fault point equivalent impedance composed of *R* and *X* or simply use *Z*. For a more conservative approach, one can use only *X* and neglect the resistance of the network. It is also permissible to consider as the fault-point prefault driving voltage, the exploitation (operating) voltage anticipated under actual service conditions, which could exceed the customarily assumed 1.00 p.u.

d) Classify the synchronous generator contributions as either remote or local. The classification of generator contributions is done according to the so-called "40% criterion" described in 8.4. According to this classification, the local and remote content of the total symmetrical fault current (NACD ratio) can therefore be estimated.

e) Adjust the calculated symmetrical short-circuit currents for dc and ac generating station decrement by applying the appropriate multipliers to the above-calculated symmetrical rms currents. Take into account the fault point *X/R* ratio as calculated per step b) and the local as well as the remote content of the fault current, as calculated per step d). Take into account circuit breaker speed, circuit breaker parting time, and circuit breaker rating structure, per 8.5. Generally speaking, the symmetrical fault current will feature both local and remote contents, particularly if in-plant generation is present. In this case, the technique of weighted interpolation, already outlined in 8.5 is advisable instead of using only remote multiplying factors. If the NACD ratio approach, for either totally or symmetrically rated circuit breakers, is used and the composite multiplier turns out to be less than unity, a value of 1.00 should be used. IEEE Std C37.010 allows for a simplified calculation when the fault currents have $X/R$ < 15 and are less than 80% of the symmetrical interrupting rating of the equipment. In this case, the calculated *E/X* current is compared directly to the circuit breaker rating.

Induction motor contributions can be considered as local, but if an extra degree of conservatism is desired, it is also permissible to consider them as remote. Generators modeling utility service-entrance points are considered to be of the remote type since, by default, they are assumed to feature no ac decrement.

## 8.6 ANSI-approved standards and interrupting duties

### 8.6.1 General considerations

Fault interrupting devices must be applied so that they are capable of performing their intended function, i.e., interrupt the fault current at a given system location, without any adverse effects for either the device itself or the system. Inability to interrupt the fault current can cause the interrupting device to fail and induce extensive damage to significant parts of the system with significant capital investment losses as well as unintended downtime and disconnection patterns. Subclause 8.6 addresses concerns relevant to fault calculations, but it should, in general, be kept in mind that before applying or even selecting a fault current interrupting device, proper regard should be given to switching requirements, particular service conditions and insulation coordination-related aspects. In fact, quite often, it is the latter that will dictate interrupting equipment selection.

Short-circuit studies are also carried out for the purposes of setting over current protective devices. Depending on the device type, different short-circuit currents may be required, barring the fact that depending on the device acting time and purpose, different fault simulations may be warranted. As a rule, however, calculations based on the subtransient impedances are adequate.

### 8.6.2 Interrupting device evaluation aspects

A fundamental quantity when properly sizing fault current interrupting devices is the fault current at the device location. Assuming that the relevant considerations accounting for the worst-case prospective fault currents have been entertained, it is common practice to assess the interrupting device duties on the basis of fault currents for the nearest system bus. This is a realistic approach when there are a number of circuit breakers connected around that bus. A feeder circuit breaker connected to load centers with no motor load, or servicing a relatively small amount of motor load, would have little effect and the circuit breaker duty would practically equal the bus duty. If the circuit breaker capabilities are found to satisfy the total calculated bus duty, then the circuit breaker is applied without any further consideration. The same rationale should also be applied to fused potential transformers on a bus since they will be subjected to the total bus fault current.

There are, however, cases where more detailed calculations may be warranted. Faults on major bus ties for instance, such as synchronizing buses, could demand more refined calculations for individual circuit breaker duties. Similar considerations may apply to feeder circuit breakers, depending on whether there is a significant downstream contribution.

In general, interrupting devices must be able to safely interrupt the prospective fault currents through them at the time they are called upon to operate. Medium- and high-voltage circuit breakers feature a delayed operation due to inherent (tripping mechanism) and/or intentional (relay acting time) time delay. Currents for evaluating interrupting requirements of medium- and high-voltage circuit breakers must be calculated according to the procedures outlined in 8.5 and 8.6, depending on the circuit breaker rating structure. However, medium- and high-voltage circuit breakers still need to meet first-cycle fault current requirements, quantified by the so-called “momentary” or “closing and latching” circuit breaker duties, in order to avoid exposing them to mechanical and thermal stresses that might seriously compromise their integrity and longevity.

### 8.6.3 First-cycle currents

Medium- and high-voltage circuit breakers are applied using either the total rms or the peak current for the first cycle in order to ascertain that the so-called “momentary” or “closing and latching” requirements are met. Procedures for calculating first-cycle currents have already been outlined in 8.5.

For low-voltage circuit breakers, IEEE Std C37.13 makes a distinction between fused and unfused circuit breakers.

Fused low-voltage circuit breakers are evaluated on the basis of the total asymmetrical rms first-cycle current. Due to the fact, however, that these circuit breakers are rated on a symmetrical basis according to IEEE Std C37.13, there is already an embedded asymmetry assumed that rests on the assumption of a 20% test power factor, equivalent to a test fault point *X/R* ratio of 4.9. This necessitates a further calculation for the circuit breaker duty only when power factors smaller than 20% (*X/R* ratios greater than 4.9) are encountered. First-cycle asymmetrical currents can be calculated, per IEEE Std C37.13, according to the Equation (66):

$$I_{asym} = I_{sym}\sqrt{1+2e^{-2\pi/(X/R)}} \tag{66}$$

Unfused low-voltage circuit breakers need to be evaluated on the basis of first-cycle peak currents. Due to the fact, however, that these circuit breakers are rated on a symmetrical basis according to IEEE Std C37.13, there is already an embedded asymmetry assumed that rests on the assumption of 15% test power factor, equivalent to a test fault point *X/R* ratio of 6.6. This necessitates a further calculation for the circuit breaker duty only when power factors smaller than 15% (*X/R* ratios greater than 6.6) are encountered. First-cycle peak currents can be evaluated, per IEEE Std C37.13, according to Equation (67):

$$I_{peak} = I_{sym}\sqrt{2}\left(1+e^{-\pi/(X/R)}\right) \tag{67}$$

## 8.7 Unbalanced short-circuit calculations

### 8.7.1 Introduction

The objective of 8.7 is to give a procedure for the calculation of unbalanced short-circuit currents on systems. The network can include equipment with decaying ac fault current sources, such as motors and generators. The application and selection of interrupting equipment based on the calculated fault current are covered in Clause 10.

The accurate calculation of unbalanced faults is expedited by the use of symmetrical components, which are covered in Clause 7. It must be emphasized that symmetrical components determine fault voltages and fault currents only. The actual line currents that flow are a combination of fault, load, and circulating currents. The load or circulating currents are determined in the prefault period under prefault conditions. The superposition theorem permits the addition of the fault currents in each branch of the network to the prefault current. In general, load currents are relatively small with respect to fault currents and often can be neglected.

### 8.7.2 ANSI guidelines

For equipment rating purposes, IEEE Std C37.010-1999 and IEEE Std C37.13-1990 basically focus on the maximum fault current magnitudes, which are the result of three-phase faults. Limited amount of attention is given to unsymmetrical faults because the interrupting duty is reduced for these types of faults. IEEE Std C37.010 does allow the line-to-ground interrupting current magnitudes to be 15% greater than a three-phase fault, provided they do not exceed the maximum current rating of the circuit breaker. As with three-phase faults, a first-cycle and interrupting-time calculation can be made with the appropriate change in machine impedances. Because the negative and zero sequence impedances do not change significantly, the line-to-ground fault current magnitudes vary less between first-cycle and interrupting-time currents as compared to the three-phase currents.

The machine positive sequence impedances used in this clause will be based on interrupting and first-cycle impedances, as given in IEEE Std C37.010-1999. The representation of synchronous machines by a varying impedance is easily adapted to other analytical techniques, such as IEC 60909.

IEEE Std C37.010 includes three other specifications to be used when calculating fault currents. These are as follows:

a) The prefault bus voltage is equal to the highest typical operating voltage at the fault point.

b) Separate resistance and reactance networks are to be used to determine the fault point *X/R* ratio. This *X/R* ratio is to be used to calculate the total asymmetrical fault current.

c) Load currents are much smaller than the fault current and neglected.

In this clause, the symmetrical ac component of the short-circuit current varies based on the time after the fault. For the purpose of simplicity and conservatism, ANSI has recommended the following simplified procedure for determining the *X/R* ratio to be applied for a particular fault. The system impedance diagram is converted to a separate resistance ($R$) diagram and a separate reactance ($X$) diagram. The resistance and reactance diagrams are then reduced to a simple resistance ($R$) and a reactance ($X$) value at the fault point. These values are then used to determine the system *X/R* for a particular fault. The *X/R* value in turn determines the system dc time constant and consequently the rate of decay of the transient dc fault current. By treating the separate $R$ and $X$ as a complex impedance, a close conservative approximation (usually within 0.5% for $X/R > 1$) to the true current can be obtained. For simplicity, this method will be used in the sample calculations.

### 8.7.3 Procedure

Some of the most important items in an unbalanced fault calculation are the sequence component one-line diagrams and the connection of the sequence networks for different types of faults. The negative sequence diagram is basically the positive sequence diagram with no voltage source(s) and with some impedances of the synchronous machine being changed. Often the assumption that the negative sequence impedances are the same as the positive sequence impedances is used. This is a fairly good assumption except for rotating machines where the negative sequence impedance is constant and the positive sequence impedance changes with the time period being studied (to account for ac decay). For first-cycle calculations, the negative sequence impedance and positive sequence impedance are similar in magnitude.

The zero sequence diagram is more complex and the impedances may not be as readily available. The type of grounding on generators and transformers must be included in the zero sequence diagrams. Transformer winding configurations, manner of grounding, and zero sequence impedances are important and have to be correctly represented or the results will be meaningless.

The steps in performing an unbalanced fault calculation are as follows:

a) Obtain sequence impedances on the apparatus such as generators, motors, and transformers and circuits such as cables, duct, and lines

b) Convert impedances to a per-unit value on a common VA base, such as 100 MVA or 10 MVA, if the per-unit system is used for calculation

c) Construct each of the three sequence impedance networks for the electrical system that is under study

d) Reduce the sequence networks to simplify calculations (as appropriate)

e) Connect the sequence network for the type of fault desired

f) Calculate the sequence currents

g) Calculate the fault and line currents

Figure 61 and Table 12 provide the positive, negative, and zero sequence diagrams for the various types of power system equipment. Figure 62, Figure 63, and Figure 64 provide the sequence diagrams for transformers. These diagrams are important because they define the flow path of ground current in a transformer and the possible isolation of ground fault currents from one voltage level to the next. Also note that the construction of the transformer (core or shell design) may affect the sequence network or zero sequence impedances.

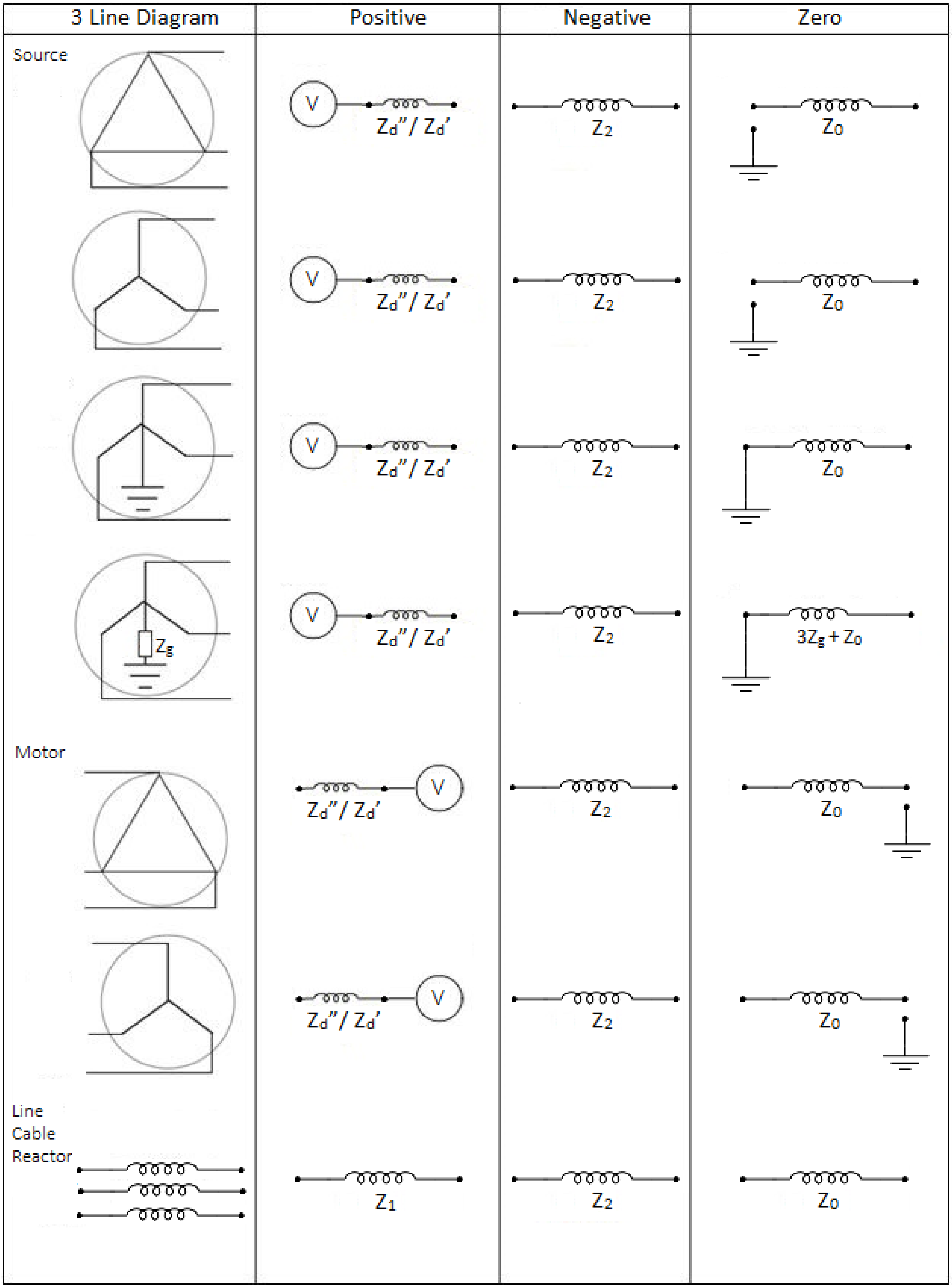



**Figure 61 —Sequence networks for power system equipment**

### Table 11 —Equipment sequence impedances

| Circuit or apparatus | Positive sequence | Negative sequence | Zero sequence | Remarks |
|---|---|---|---|---|
| Utility[a] | $R_1$, $X_1$ | $R_2$, $X_2$ | $R_0$, $X_0$ | Often $X_2 = X_1$ |
| Synchronous generator | $R_1$, $X''_d$, $X'_d$ | $R_2$, $X_2$ | $R_0$, $X_0$ | Usually grounded through a resistor or transformer |
| Synchronous condenser | $R_1$, $X''_d$, $X'_d$ | $R_2$, $X_2$ | $R_0$, $X_0$ | Neutral may or may not be grounded |
| Synchronous motor | $R_1$, $X''_d$, $X'_d$ | $R_2$, $X_2$ | $R_0$, $X_0$ | Neutral seldom grounded |
| Induction motor | $R_1$, $X''$ | $R_2$, $X_2$ | $R_0$, $X_0$ | Neutral not grounded |
| Transformer | $R_1$, $X_1$ | $R_1$, $X_1$ | $R_0$, $X_0$ | Wye winding usually solidly or impedance grounded |
| Auto-transformer | $R_1$, $X_1$ | $R_1$, $X_1$ | $R_0$, $X_0$ | Usually solidly grounded |
| Reactor | $R_1$, $X_1$ | $R_1$, $X_1$ | $R_1$, $X_1$ | |
| Neutral resistor | — | — | $3R_1$ | |
| Neutral reactor | — | — | $3X_1$ | |
| Cable | $R_1$, $X_1$ | $R_1$, $X_1$ | $R_0$, $X_0$ | |
| Overhead lines | $R_1$, $X_1$ | $R_1$, $X_1$ | $R_0$, $X_0$ | |
| Busway | $R_1$, $X_1$ | $R_1$, $X_1$ | $R_0$, $X_0$ | |

[a] Note that the utility system representation will typically be a Thevenin equivalent obtained by a reduction of the utility system at the fault point. The equivalent impedance is often a worst-case value (to give the highest fault current) and will not be modified for ac decay.

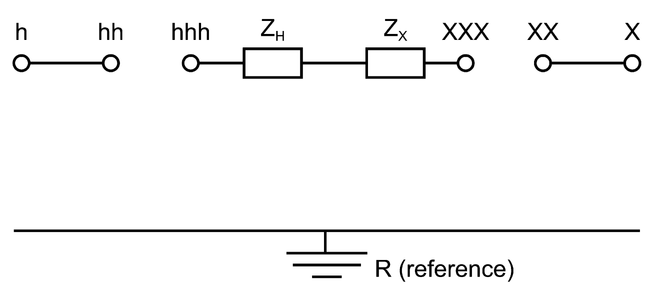



Figure 62 —Sequence networks for transformers

### Table 12—Connection specifications for Figure 62

| Transformer connections | | Positive or negative sequence | | Zero sequence | |
|---|---|---|---|---|---|
| **Winding H** | **Winding L** | **Winding H** | **Winding L** | **Winding H** | **Winding L** |
| Delta | Wye | Short hh to hhh | Short xx to xxx | Short hhh to R | Open xxx to xx |
| Delta | Solidly grounded wye | Short hh to hhh | Short xx to xxx | Short hhh to R | Short xx to xxx |
| Delta | Wye (grounded through $Z_{gnd}$) | Short hh to hhh | Short xx to xxx | Short hhh to R | Connect xx to xxx through $3Z_{gnd}$ |
| Delta | Delta | Short hh to hhh | Short xx to xxx | Short hhh to R | Short xxx to R |
| Wye | Wye | Short hh to hhh | Short xx to xxx | Open hhh to hh | Open xxx to xx |
| Wye | Solidly grounded wye | Short hh to hhh | Short xx to xxx | Open hhh to hh | Short xx to xxx |
| Wye | Wye (grounded through $Z_{gnd}$) | Short hh to hhh | Short xx to xxx | Open hhh to hh | Connect xx to xxx through $3Z_{gnd}$ |
| Solidly grounded wye | Solidly grounded wye | Short hh to hhh | Short xx to xxx | Short hh to hhh | Short xx to xxx |
| Solidly grounded wye | Wye (grounded through $Z_{gnd}$) | Short hh to hhh | Short xx to xxx | Short hh to hhh | Connect xx to xxx through $3Z_{gnd}$ |
| Wye (grounded through $Z_{gnd}$) | Wye (grounded through $Z_{gnd}$) | Short hh to hhh | Short xx to xxx | Connect hh to hhh through $3Z_{gnd}$ | Connect xx to xxx through $3Z_{gnd}$ |

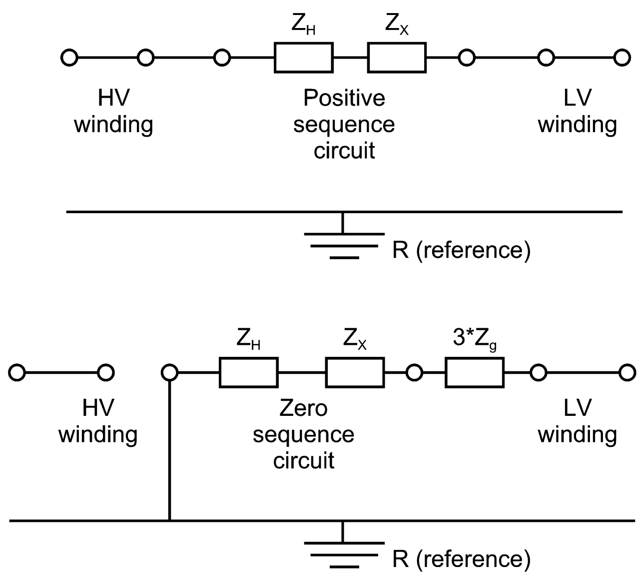



**Figure 63—Example sequence networks for delta to wye (impedance grounded) transformer connection**

Figure 64 shows the diagram used to explain the sequence networks for three-winding (three-phase) transformers. The connections are based on the information given in Table 12. For example, assume the following transformer connections: a delta (primary winding, h) to solidly grounded wye (secondary winding, x) connection with the tertiary winding (t) connected in delta. The positive and negative sequence network would consist of shorting hh to hhh, xxx to xx, and ttt to tt. The zero sequence network would have the h and t windings with hh to hhh and tt to ttt open and with hhh and ttt shorted to reference. The secondary would have xxx connected to xx through a zero impedance branch.

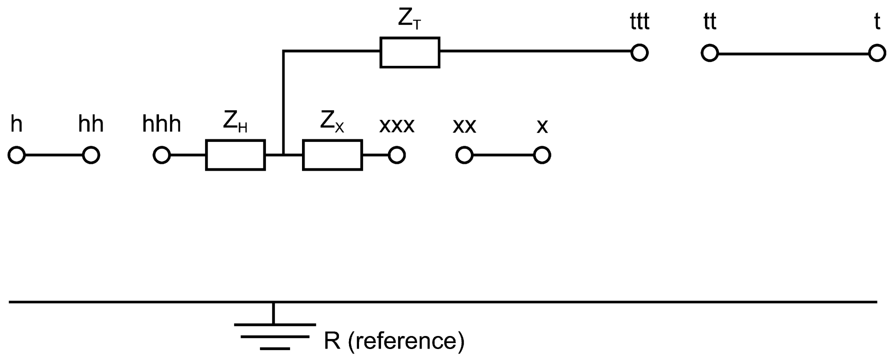



**Figure 64—Sequence networks for transformers with tertiary windings**

### 8.7.4 Connection of sequence networks

The connections of the sequence networks for three-phase, line-to-ground, line-to-line, and double line-to-ground faults are given in Figure 65, Figure 66, Figure 67, and Figure 68. The diagrams show the direction and location of the sequence currents and the sequence voltages. It is important to recognize the defined positive directions for current flow and voltage polarity. Attention to the defined convention is necessary so that the correct phase values can be obtained from the sequence values. The references in Annex A can be consulted for more detail on the development of the sequence network connection, or to learn how to calculate other unbalances, such as an open phase.

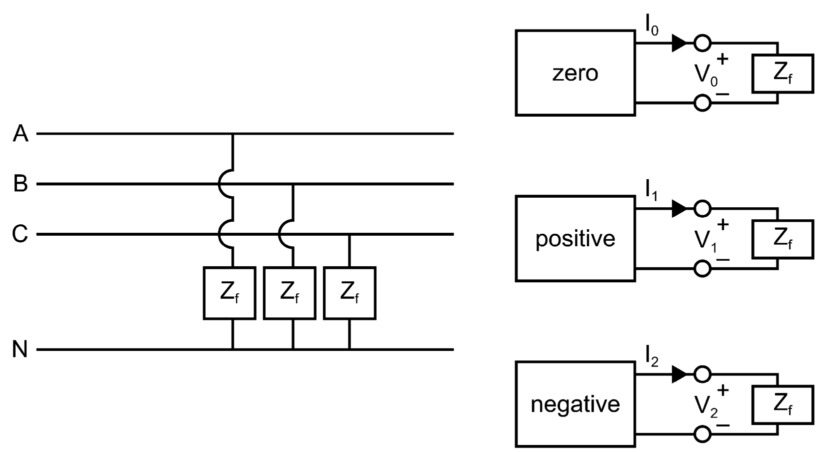



**Figure 65—Connection of sequence networks for a three-phase fault**

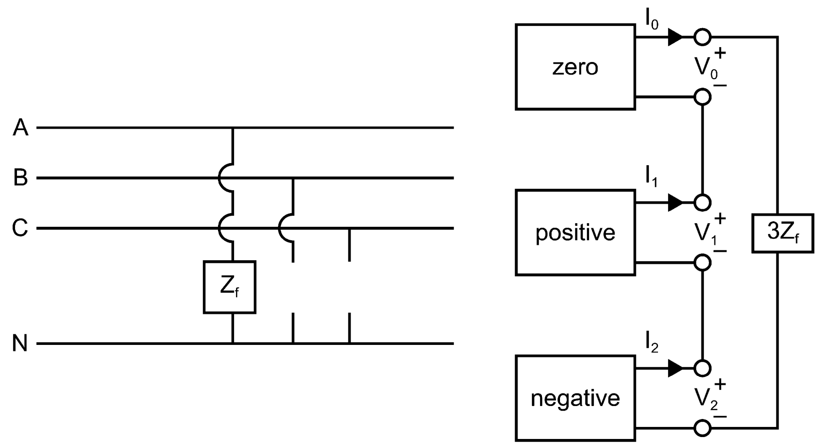



**Figure 66—Connection of sequence networks for a line-to-ground fault**

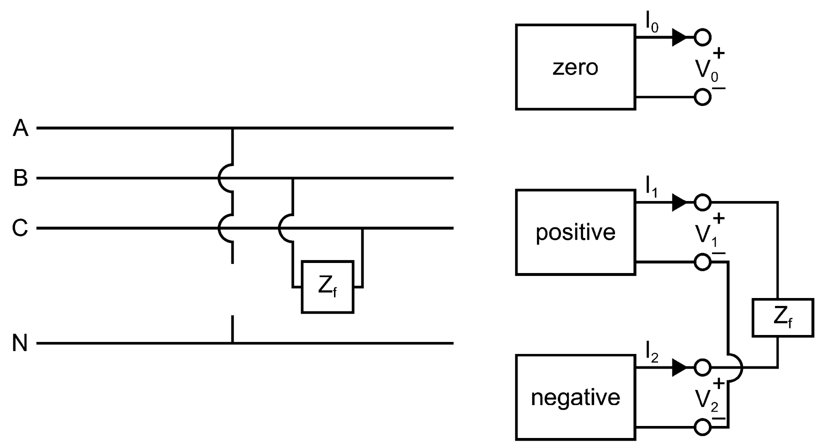



**Figure 67—Connection of sequence networks for a line-to-line fault**

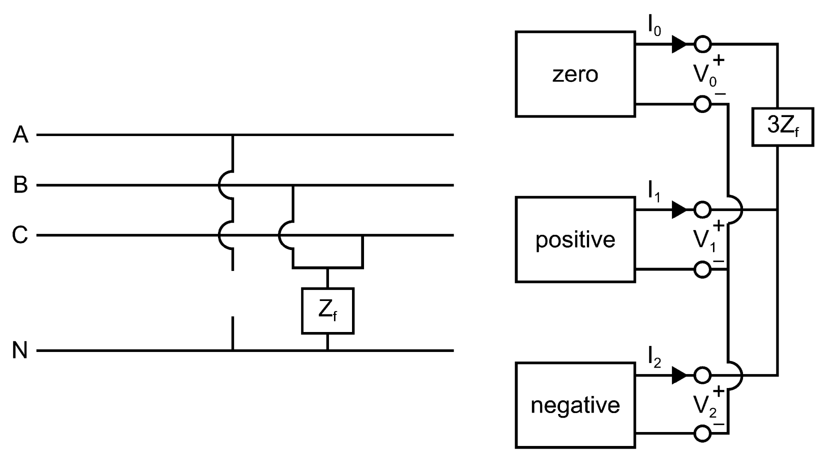



**Figure 68—Connection of sequence networks for a double line-to-ground fault**

# 9. Application of short-circuit interrupting equipment per ANSI standard

## 9.1 Introduction

This clause describes the application of electrical power system interrupting equipment for three-phase and line-to-ground short-circuit currents. The fault currents used are from the one-line diagram used throughout this book and includes generator, induction and synchronous motors contributions. The application of interrupting equipment, in some cases, requires more than comparing an interrupting current given on the nameplate to the calculated duty. The calculation of fault currents in accordance to ANSI-approved standards are covered in Clause 8. The term *duty* as used in this text is the maximum symmetrical fault current times any multipliers, which makes the resulting current directly comparable with the equipment rating.

The objective of this clause is to give examples of taking available interrupting equipment data and making comparisons to the calculated short-circuit duty. The capability of the interrupting equipment to adequately interrupt short-circuit currents is a safety as well as a system and equipment protection consideration. The National Electrical Code® (NEC®) (NFPA 70, 2005 Edition) states that, "Equipment intended to break current at fault levels shall have an interrupting rating sufficient for the nominal circuit voltage and the current that is available at the line terminals of the equipment." (See NEC, Section 110-9.) "The overcurrent protective devices, the total impedance, the component short-circuit withstand ratings, and other characteristics of the circuit to be protected shall be so selected and coordinated as to permit the circuit protective devices that are used to clear a fault without the occurrence of extensive damage to the electrical components of the circuit." (See NEC, Section 110-10.)

## 9.2 Application considerations

Once a short-circuit calculation has been made using the best data available, the application or verification of circuit breaker, fuse, switches, and other equipment ratings needs to be made. Subclause 9.8 provides a list on equipment that may have to be checked against the short-circuit fault currents. Depending on the purpose of the fault calculations, not all equipment listed in 9.8 will need to be checked. A number of items from the short-circuit calculations have to be considered when comparing the fault currents against the equipment. These are as follows:

a) Circuit voltage

b) Circuit fault current

c) Fault current *X/R* ratio

d) Equipment first-cycle withstand capabilities

e) Equipment first-cycle interrupting current capabilities

f) Equipment interrupting-time and current capabilities

g) Equipment maximum application voltage and maximum interrupting current

h) Equipment minimum application voltage and minimum interrupting current

i) Equipment interrupting test *X/R* ratio

j) Non-interrupting equipment fault current withstand and thermal capabilities

Several methods are used to modify the fault current or circuit breaker rating when a multiplier is required because of system conditions. A derating factor can be applied to the interrupting device rating or a multiplier can be applied to the current. In this book the latter will be used. In general, the multiplier on the

current is preferred because the interrupting equipment ratings will remain the same for all buses at the same voltage. Otherwise, the adjusted interrupting equipment current ratings may differ depending on the fault current *X/R* ratio.

Table 13 gives the general test *X/R* ratios of interrupting equipment.

**Table 13—Minimum test *X/R* ratios**

| Type of equipment | First-cycle current | First-cycle *X/R* | Interrupting time or short time *X/R* |
|---|---|---|---|
| Low-voltage power circuit breaker (iron frame breaker) | Peak | 6.59 | 6.59 |
| Low-voltage molded and insulated case breakers with interrupting ratings > 20 kA | Peak | 4.9 | 4.9 |
| Low-voltage molded and insulated case breakers with interrupting ratings 10 kA to 20 kA | Peak | 3.18 | 3.18 |
| Low-voltage molded and insulated case breakers with interrupting ratings < 10 kA | Peak | 1.73 | 1.73 |
| Fused low-voltage power circuit breakers | Peak | 4.9 | 4.9 |
| Low-voltage busway | Peak | 4.9 | 4.9 |
| High-voltage power circuit breaker | rms | 25 | 15 |
| Power fuse | rms | 15 | — |
| Distribution fuse | rms | 10 | — |
| Distribution air cutout fuse | rms | 5 to 15, depends on kV rating | — |
| Distribution oil cutout fuse | rms | 9 to 12, depends on kV rating | — |
| Switches (withstand rating) | rms | 25 | — |
| High-voltage bus duct | | 25 | — |

## 9.3 Equipment data

Equipment rating data for a particular type of equipment can vary over several years of manufacture depending on improvements in the equipment, special limitation of the equipment, or changes in the rating structure. The recommended ratings and required data to be placed on equipment nameplates is given in the appropriate ANSI, IEEE, and NEMA standards for the equipment. Short-circuit test requirements given by NEMA, Underwriters Laboratories, ANSI, or IEEE are generally the same for the type of equipment involved. Not all manufacturers follow the standards' recommended rating structure. Some interrupting equipment may be sized to fit an area not covered by the standards, or the equipment may have a higher or lower interrupting capability than suggested by the standard recommended ratings system.

Several examples of equipment rating changes are given below. The broad range of GE type AM-13.8-500 medium-voltage class of circuit breakers used in metal-clad switchgear covers many years. During the years of manufacture, the ANSI rating structure was revised and the circuit breaker design was changed to accommodate the change. In the mid-1960s the circuit breaker design and nameplate reflected the ANSI change of total current method of testing to the symmetrical current method of testing. Unless additional data are furnished, (series number, year of manufacture, complete nameplate data) there is no way to determine the actual rating of the circuit breaker. A second example is the BBC type xx-HK-xxx medium-voltage class of circuit breakers rated on a symmetrical current basis have a five-cycle interrupting time.

However, the circuit breaker nameplate and literature gives a 1.2 asymmetry factor. This information indicates that the circuit breaker has a two-cycle contact parting time rather than the three-cycle contact parting normally associated with five-cycle interrupting-time circuit breakers. A third case is that S&C power fuses literature provides varying symmetrical interrupting ratings depending on the system fault *X/R* ratio. Normally most manufacturers of power fuses provide only one interrupting rating at an *X/R* ratio of 15.

Based on the previous discussion, rating variations from different vendors are possible and care should be exercised in using general equipment data. The preferred order of obtaining equipment data are as follows:

- Equipment nameplate
- Manufacturer's literature
- ANSI, IEEE, or NEMA standards

## 9.4 Fully-rated systems

In a fully-rated system, all interrupting equipment is applied to interrupt the total fault current at the point of the fault. All high-voltage circuit breakers require a fully-rated system. All low-voltage power circuit breakers (iron frame) require a fully-rated system. All low-voltage systems greater than 480 volts require a fully-rated system.

The use of first half-cycle current-limiting interrupting devices on a high-voltage system to reduce the amount of fault current the circuit breakers have to interrupt is not covered by the standards. The manufacturer of a circuit breaker used in such a manner should be consulted to determine its acceptability and change in warranty, if any.

Application of electronically triggered fuses should be undertaken with caution. These devices are generally available for use at nominal system voltages of 600 V through 36 kV, but depend on an independently powered current-sensing and tripping unit to set off small explosive charges within fuse-like inserts to accomplish current interruption within the first 1/4-cycle of fault initiation. If the tripping unit should fail to initiate the interruption and reduce the short-circuit duty, downstream equipment may be applied beyond its ratings.

Section 110-9 of the NEC requires that fault interrupting devices have an interrupting rating sufficient to withstand the current to be interrupted. This is commonly known as a fully-rated system. However, low-voltage series rated equipment is allowed.

## 9.5 Low-voltage series-rated equipment

Series rating on equipment allows the application of two series interrupting devices for a condition where the available fault current is greater than the interrupting rating of the downstream equipment. Both devices share in the interruption of the fault and selectivity is sacrificed at high fault levels. Selectivity should be maintained for tripping currents caused by overloads.

The NEC states, "If a circuit breaker is used on a circuit having an available fault current higher than its marked interrupting rating by being connected on the load side of an acceptable overcurrent protective device having the higher rating...this series combination rating shall be marked on the end use equipment." (See NEC, Section 249-6.) In this case, the short-circuit rating assigned to the combination of the series devices can be higher than the lowest downstream rated device of the combination.

In a series combination of fuses or circuit breakers, series-rated equipment must meet some strict rules in order to be applied:

a) Series-rated combinations should be selected by a registered professional engineer whose primary occupation is the design and maintenance of electrical installations. The design documents should be stamped with the seal of the professional engineer.

b) A series combination is recognized for series application by a third-party organization, such as UL. UL 489-2002 outlines the test connections and procedures for proof of series combination ratings. Analytical methods, such as the "up-over-and-down" method for applying fuses, may not be used for circuit breakers that exhibit contact parting in the first half-cycle.

c) The tested combination does not allow for faults closer than four feet from the load side circuit breaker.

d) The current in the two interrupting devices must be the same current. Motor fault current contribution that would allow the downstream circuit breaker to have a higher current as compared to the upstream circuit breaker/fuse is not allowed.

e) Series ratings apply to systems at 600 V and below.

f) The series rating test has been made at only one power factor, whereas the actual fault power factor could vary widely.

g) Since the load circuit breaker is subject to higher-than-rated fault currents, it should be thoroughly checked and tested after each fault operation.

h) Series ratings apply for selected low-voltage equipment (molded-case circuit breakers and current-limiting fuses).

i) Upstream circuit breaker must have an instantaneous trip. Upstream fuses must be current limiting.

j) There is no limitation on physical distance between interrupting devices.

A listing of the tested combinations can be obtained from the UL Recognized Component Directory (UL-RCD). Usage of series-rated protective devices does not lead to a coordinated selective system but to a protective system, wherein the system reliability is sacrificed because of the loss of selectivity of protective equipment.

## 9.6 Low-voltage circuit breaker short-circuit capabilities less than rating

The ANSI test standard for low-voltage power circuit breakers describes a short-circuit test for circuit breakers where full line-to-line voltage is applied across an interrupting pole of a circuit breaker. For this condition, the circuit breaker must be capable of interrupting at least 87% of its three-phase interrupting rating. For a single-phase system where two poles of a three-phase circuit breaker are used to interrupt the short-circuit, the one pole, full voltage, 87% capability does not apply because each pole "sees" 50% of the line-to-line voltage, which is less than the normal line-to-neutral voltage of a three-phase system. Using a single pole of a three-phase circuit breaker to interrupt a single-phase line-to-line short-circuit requires that the circuit breaker single-pole voltage capability be greater than the normal line-to-neutral voltage of the system or a reduced interrupting rating will apply.

The most likely cause of an interruption of a line-to-line short-circuit by one pole of a circuit breaker is a double line-to-ground short-circuit in a three-phase system that is not solidly wye-grounded, such as an ungrounded system, high resistance grounded system, or corner of the delta grounded system. Full line-to-line recovery voltage can occur across a single interrupting pole when one phase is grounded on the source side of a circuit breaker and another phase is grounded simultaneously on the load side. For a corner of the delta grounded system, this might be a common occurrence. The situation is less likely to occur in high resistance grounded or ungrounded systems where operating procedures require the first ground to be removed as soon as practical.

The single-pole interruption problem should not be a concern with low-voltage power circuit breakers because they are tested to meet the criteria in IEEE Std C37.010-1999. The maximum line-to-line first-cycle short-circuit duty is 87% of the three-phase duty in a three-phase system. If the power circuit breaker is correctly applied for a three-phase short-circuit duty, then it is correctly applied for the line-to-line duty independent of the system grounding. The limiting application may be for a line-to-ground fault on a solidly grounded system where the line-to-ground fault current may be greater than the three-phase current, e.g., on the secondary of a transformer.

However, the single-pole interrupting ratings assigned to low-voltage molded case or insulated case circuit breakers may be based on UL or NEMA standard values, which may be lower than ANSI requirements. If this restricts an application, the manufacturer should be consulted because single-pole tests using voltages and currents higher than literature values may have been performed, relieving the restriction.

## 9.7 Equipment checklist for short-circuit currents evaluation

The following is a list of items that may need to be compared against the calculated fault levels. Depending on the purpose of the short-circuit study, not all items will need to be checked. The list does show that there are more devices affected by short-circuit than just interrupting devices, such as fuses and circuit breakers.

a) *Fuses*—Fuse voltage rating and first-cycle interrupting current.

b) *High-voltage circuit breakers*—Voltage rating, first-cycle current, interrupting current. A system rated 4.8 kV often requires equipment rated at 7.2 kV because the upper limit of some 4.16 kV class of equipment is 4.76 kV.

c) *Low-voltage circuit breakers*—Voltage rating, first-cycle current (interrupting), short time current rating if no instantaneous is supplied, and single-pole interrupting rating.

d) *Switches*—First-cycle current for withstand capabilities.

e) *Switchgear,* motor *control centers*—First-cycle current for bus bracing and molded case interrupters.

f) *Reclosers*—Voltage rating, first-cycle current, interrupting current.

g) *Cable heating limits*—First-cycle, interrupting, and time-delay relay currents. This check is more important on systems with time-delay tripping and where selective relay operating times are required. The heat generated in the cable during the fault could overheat the insulation and deteriorate or melt it. Extremely small cable while within its load rating could act as a fuse under high fault currents.

h) *Line heating limits*—First-cycle, interrupting, and time-delay relay currents. This check is more important on systems with time-delay tripping. The heat generated in the line during the fault could overheat the line causing more sag and possibly a second fault, injury, or line meltdown.

i) *Current-limiting reactors*—First cycle to check the through current. Per ANSI 57.16, the rms short-circuit should be less than 33.33 times the rated rms current.

j) *Busways and* bus *ducts*—First-cycle current to check the bus bracing.

k) *Transformers*—First-cycle and time-delay currents for mechanical and thermal withstand limits. The transformer overcurrent relays should be set to protect these limits per ANSI C57.109.

l) *Line carrier frequency wave traps*—First-cycle and time-delay currents for mechanical and thermal withstand limits. Wave traps can be the limiting item on a transmission line.

m) *Current transformers*—First-cycle and time-delay currents for the mechanical and thermal withstand limits. High primary currents can cause current transformer saturation that may affect relay operation.

n) *Generators*—First-cycle line-to-ground fault currents on non-impedance grounded generators can have line-to-ground fault currents that are greater than the three-phase fault current. The winding bracing of the generator is based on three-phase fault currents.

o) *Grounding resistors and reactors*—Time-delay line-to-ground fault currents if not properly relayed can exceed the short time ratings of generator and transformer grounding devices.

p) *Series capacitors*—First-cycle fault currents will result in high voltages across the capacitors that may exceed both the transient current and voltage capability of the capacitors and its protective surge equipment.

## 9.8 Equipment phase duty calculations

### 9.8.1 Introduction

Subclause 9.8.2 calculates the first-cycle and interrupting-time fault current duties on the above listed equipment. The example system is provided in IEEE Std 3002.2. Please refer to IEEE Std 3002.2 for detailed information and equipment parameters. The one-line diagram of the faulted bus (Bus B) and symmetrical fault currents used to calculate the duties are displayed in Figure 69 and Figure 70. These results are obtained when tie breakers are closed for the most conservative operating condition.

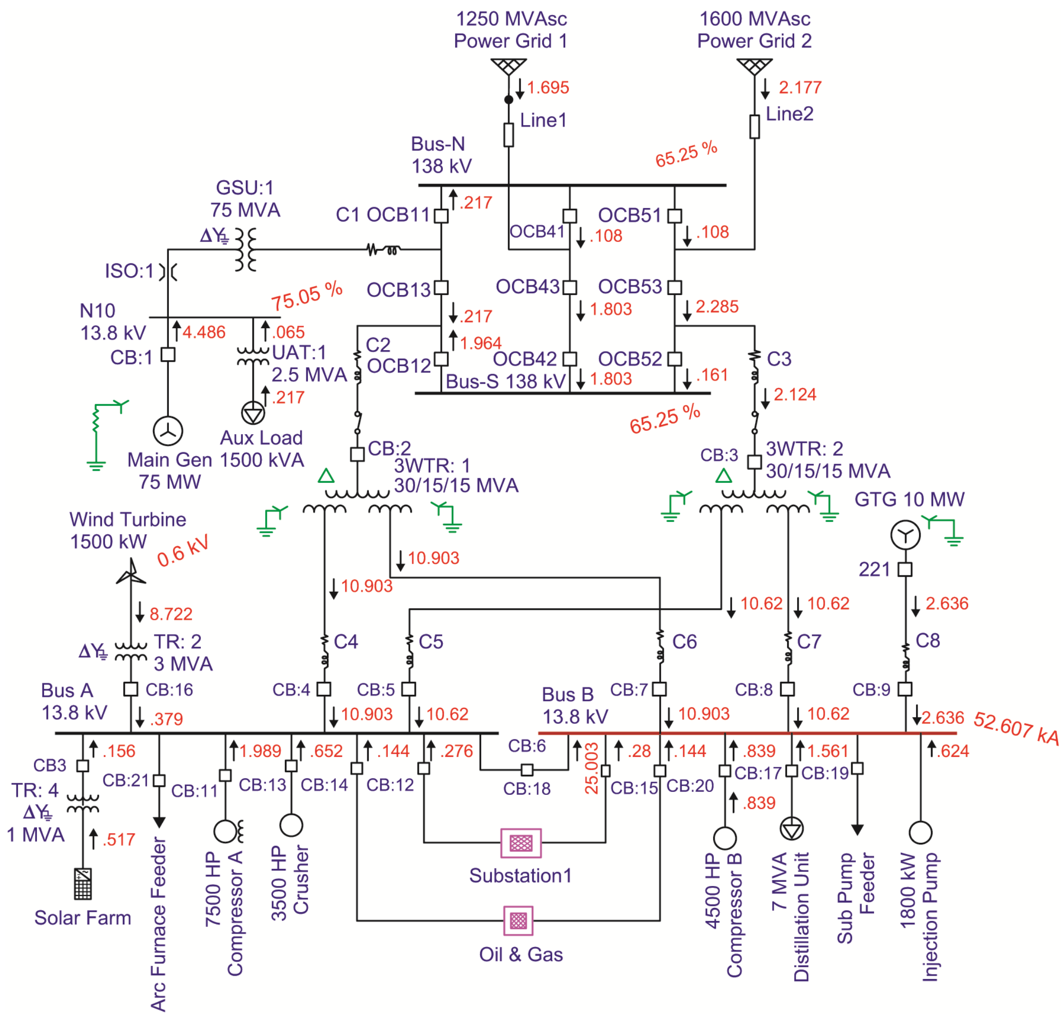



**Figure 69—One-line diagram with Bus B faulted
Arrows represent fault contributions in kA**

**SHORT-CIRCUIT REPORT**

3-phase fault at bus: **Bus B**

Prefault voltage = 14.214 kV = 103.00 % of nominal bus kV (13.800 kV)
= 103.00 % of base (13.800 kV)

| Contribution | | 1/2 Cycle | | | | | 1.5 to 4 Cycle | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| From Bus ID | To Bus ID | % V From Bus | kA Real | kA Imaginary | Imag. /Real | kA Symm. Magnitude | % V From Bus | kA Real | kA Imaginary | Imag. /Real | kA Symm. Magnitude |
| Bus B | Total | 0.00 | 3.841 | -52.466 | 13.7 | 52.607 | 0.00 | 3.677 | -50.080 | 13.6 | 50.215 |
| N15 | Bus B | 4.31 | 0.789 | -10.874 | 13.8 | 10.903 | 4.31 | 0.788 | -10.873 | 13.8 | 10.902 |
| N17 | Bus B | 4.19 | 0.763 | -10.593 | 13.9 | 10.620 | 4.19 | 0.763 | -10.592 | 13.9 | 10.619 |
| N18 | Bus B | 1.11 | 0.144 | -2.632 | 18.3 | 2.636 | 1.11 | 0.144 | -2.632 | 18.3 | 2.636 |
| N22 | Bus B | 1.51 | 0.050 | -0.276 | 5.5 | 0.280 | 0.88 | 0.030 | -0.160 | 5.4 | 0.163 |
| N25 | Bus B | 1.46 | 0.020 | -0.143 | 7.0 | 0.144 | 0.66 | 0.009 | -0.065 | 7.0 | 0.065 |
| N30 | Bus B | 0.00 | 0.000 | 0.000 | 999.9 | 0.000 | 0.00 | 0.000 | 0.000 | 999.9 | 0.000 |
| Injection Pump | Bus B | 129.22 | 0.009 | -0.624 | 66.4 | 0.624 | 129.22 | 0.006 | -0.416 | 66.4 | 0.416 |
| Distillation Unit | Bus B | 103.00 | 0.155 | -1.553 | 10.0 | 1.561 | 103.00 | 0.104 | -1.035 | 10.0 | 1.041 |
| Compressor B | Bus2 | 107.68 | 0.038 | -0.838 | 22.0 | 0.839 | 107.68 | 0.025 | -0.559 | 22.0 | 0.559 |
| B1 | Bus A | 0.00 | 0.000 | 0.000 | 999.9 | 0.000 | 0.00 | 0.000 | 0.000 | 999.9 | 0.000 |
| N14 | Bus A | 4.31 | 0.789 | -10.874 | 13.8 | 10.903 | 4.31 | 0.788 | -10.873 | 13.8 | 10.902 |
| N16 | Bus A | 4.19 | 0.763 | -10.593 | 13.9 | 10.620 | 4.19 | 0.763 | -10.592 | 13.9 | 10.619 |
| N21 | Bus A | 1.49 | 0.048 | -0.272 | 5.6 | 0.276 | 0.86 | 0.029 | -0.158 | 5.5 | 0.160 |
| N24 | Bus A | 1.46 | 0.020 | -0.143 | 7.0 | 0.144 | 0.66 | 0.009 | -0.065 | 7.0 | 0.065 |
| N19 | Bus A | 17.37 | 0.014 | -0.379 | 28.1 | 0.379 | 12.27 | 0.009 | -0.268 | 29.8 | 0.268 |
| N20 | Bus A | 21.40 | 0.152 | -0.032 | 0.2 | 0.156 | 21.40 | 0.152 | -0.032 | 0.2 | 0.156 |
| Crusher | Bus A | 107.68 | 0.030 | -0.652 | 22.0 | 0.652 | 107.68 | 0.020 | -0.434 | 22.0 | 0.435 |
| Compressor A | Bus A | 107.68 | 0.057 | -1.988 | 35.0 | 1.989 | 107.68 | 0.038 | -1.326 | 35.0 | 1.326 |

**Figure 70—Bus B fault current and first level contributions**

### 9.8.2 Breakers (13.8 kV)

The high-voltage circuit breakers on Bus B must be evaluated on both first-cycle and interrupting-time bases. The first-cycle duty is compared against the close and latch rating of the symmetrical rated circuit breakers and the momentary rating of the total current rated circuit breakers. The total symmetrical Bus B fault current is 52.607 kA, and the maximum current that a circuit breaker on that bus can see is that for breaker CB:15, the smallest bus current contribution. The breaker current is approximately 52.607 – 0.28 = 52.327 kA symmetrical. Since the circuit breaker duty is 99.46% of the bus duty, the more conservative bus fault currents will be used as circuit breaker duties.

Some of the more recent circuit breakers also have a peak current given on the nameplate for the close and latch rating. This peak rating is 2.6 times the circuit breaker maximum interrupting current.

The first-cycle test *X/R* for these circuit breakers is 25 and Table 14 provides the comparisons of duty to ratings. The equation for the first-cycle rms asymmetrical current is shown in the equations below:

$$\tau = 0.49 - 0.1e^{-\frac{X}{3R}} \tag{68}$$

$$I_{rms} = I_{sym}\sqrt{\left(1 + 2e^{-\frac{2\pi\tau R}{X}}\right)} \tag{69}$$

**Table 14—First-cycle evaluation with Bus B faulted**

| Device | | Momentary duty | | | | | Device capability | | |
|---|---|---|---|---|---|---|---|---|---|
| ID | Type | Sym. kA rms | X/R ratio | M.F. | Asym. kA rms | Asym. kA peak | Sym. kA rms | Asym. kA rms | Asym. kA peak |
| Bus B | Switchgear | 52.607 | 15.5 | 1.528 | 80.361 | 135.146 | | 100.000 | 168.800 |
| CB:19 | 3-cycle symmetrical circuit breaker (CB) | 52.607 | 15.5 | 1.528 | 80.361 | 135.146 | | 100.700 | 170.000 |
| CB:20 | 3-cycle sym. CB | 52.607 | 15.5 | 1.528 | 80.361 | 135.146 | | 100.700 | 170.000 |
| CB:7 | 3-cycle sym. CB | 52.607 | 15.5 | 1.528 | 80.361 | 135.146 | | 100.700 | 170.000 |
| CB:17 | 3-cycle total CB | 52.607 | 15.5 | 1.528 | 80.361 | 135.146 | | 100.700 | 170.000 |
| CB:8 | 3-cycle sym. CB | 52.607 | 15.5 | 1.528 | 80.361 | 135.146 | | 100.700 | 170.000 |
| CB:9 | 3-cycle sym. CB | 52.607 | 15.5 | 1.528 | 80.361 | 135.146 | | 100.700 | 170.000 |
| CB:18 | 3-cycle sym. CB | 52.607 | 15.5 | 1.528 | 80.361 | 135.146 | | 100.700 | 170.000 |
| SW6 | Single pole single throw (SPST) switch | 52.607 | 15.5 | 1.528 | 80.361 | 135.146 | | 100.000 | 0.000 |
| CB:6 | 3-cycle sym. CB | 52.607 | 15.5 | 1.528 | 80.361 | 135.146 | | 100.700 | 170.000 |
| CB:15 | 3-cycle sym. CB | 52.607 | 15.5 | 1.528 | 80.361 | 135.146 | | 100.700 | 170.000 |

The interrupting circuit breaker duty requires additional information concerning the speed of the circuit breaker, the test procedure used for the circuit breaker at the time of manufacture, total symmetrical fault current, fault current *X/R* ratio, and the amount of current from nearby generators. Clause 8 went into detail on calculating the amount of current from each generator, therefore to avoid repeating this detail, the currents will be taken directly from the computer printout. For each fault, the amount of the generator current considered local from each will have to be determined. When the generator fault current is greater than 40% of a generator terminal fault current, then the current is considered local. Table 15 summaries these findings at the bus fault voltage.

**Table 15—Identification of generator currents (kA) at Bus B**

| Bus fault | Power grid generator | Fault contribution | Terminal fault current | Terminal fault contribution | 40% ratio check[a] | Status |
|---|---|---|---|---|---|---|
| Bus B | Main generator | 4.49 | 47.74 | 19.99 | 22.5% | Remote |
| Bus B | GTG | 2.64 | 42.56 | 2.66 | 99.2% | Local |

[a] Ratio of contribution to Bus B fault over contribution to terminal fault.

The next item to be determined is the weighing factor of the remote and local currents. IEEE Std C37.010 allows several options in regard to the treatment of motors. They can be considered all remote, or all local. The local and remote data are used to determine the interrupting current multiplier. The following listing calculates the ratio based on several options. The ratio is commonly called the no ac decay current (NACD) ratio.

*Option 1—Most conservative*

Consider all source current remote; this will give the highest multiplier and will assume no ac decay.

The NACD ratio = 1.0. This option is the one most used for device duty evaluations.

*Option 2—Less conservative*

Consider the motor contribution to be remote. The equation below does this by knowing the total bus fault current and the amount of current identified as local. NACD = (total – local)/total.

*Option 3—Least conservative*

Consider the motor contribution to be local. The equation below does this by knowing the total bus fault current and the amount of current identified as remote from the major sources.

Bus B has circuit breakers that were manufactured under two different test procedures. The older circuit breakers (CB:17) were tested under the total current basis of rating and the newer circuit breakers (CB:15) were tested under the symmetrical current basis of rating. From the curves of Figure 56 and Figure 57, the duty multipliers can be determined by the following steps.

*Step 1*—Determine the total current multipliers from the remote curves of Figure 56 based on the fault point *X/R* ratio. These multipliers can be taken from the curves or calculated from the following equation:

$$\left(1+2\mathrm{e}^{\frac{-4\pi C}{X/R}}\right)^{\frac{1}{2}}$$

Note that the circuit breakers on Bus B have an asymmetrical rating factor, or S factor, of 1.2. This means that the three-cycle interrupting-time circuit breaker has a contact parting time of two.

*Step 2*—Determine the local current multipliers from the local curves of Figure 56 and Figure 57(a) based on the fault point *X/R* ratio. These points can be taken from the curves or calculated from the empirical equations given in Clause 8.

*Step 3*—The final step is to adjust the multipliers based on the NACD ratio. Ratios of 1.0 or 0.0 can use the multipliers directly. The duty multiplier is:

$$(\text{remote multiplier} - \text{local multiplier}) \times \text{NACD ratio} + \text{local multiplier}$$

Figure 71 displays parameters of a typical symmetrical rated circuit breaker rated at 15 kV. The circuit breaker has a constant MVA rating between the rated maximum voltage and the voltage that results in the maximum interrupting kA (11.6 kV). The constant MVA rating is equal to $\sqrt{3} \times \text{max kV} \times \text{rated interrupting kA}$. When the circuit breaker is installed on a bus with voltage less than the max kV, its interrupting current capability increases. Applying the circuit breaker at voltages lower than 11.6 kV, the circuit breaker is a constant current interrupting device. The circuit breaker interrupting rating at 13.8 kV is shown in Equation (70):

$$\frac{727\ \text{MVA}}{13.8\ \text{kV}} / \sqrt{3} = 30.4\ \text{kA} \tag{70}$$

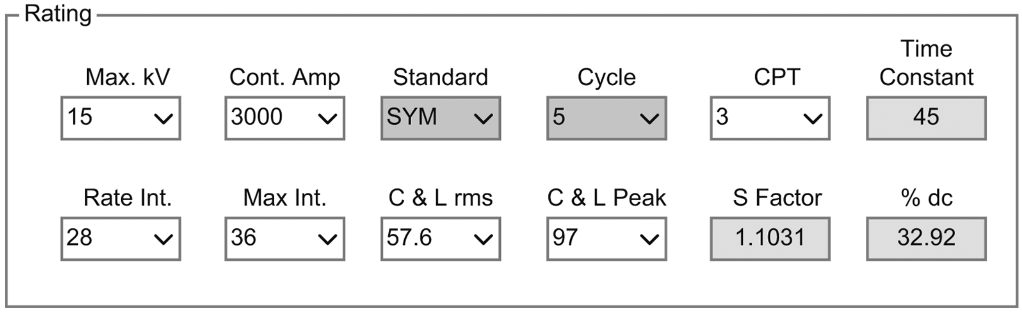



**Figure 71 —Symmetrical current rated circuit breaker parameters**

In general, for a symmetrical current rated circuit breakers, the interrupting current at its bus voltage is calculated by:

$$\frac{\text{rated maximum voltage}}{\text{bus voltage}} \times \text{rated short-circuit current}$$

The interrupting capability cannot exceed:

rated short-circuit current × voltage range factor

or

$$\frac{\text{first cycle (close and latch)}}{\text{voltage range factor}}$$

The voltage range factor is equal to the maximum interrupting kA divided by rated interrupting kA. The values should be the same when rounded off.

For the circuit breaker shown in Figure 71, its interrupting rating at 13.8 kV is:

$$15.0 \times \frac{28}{13.8} = 30.4 \text{ kA}$$

The current does not exceed 36 kA, the circuit breaker maximum interrupting rating.

In the above example with the 13.8 kV tie circuit breaker closed, the circuit breaker duty current is less than its rating and the circuit breakers are correctly applied.

### 9.8.3 Bus disconnect switch (13.8 kV)

Bus disconnect switch (Bus B, SW 6) based on standards has a first-cycle asymmetry factor of 1.6 that is equivalent to a fault *X/R* ratio of 25. The calculated symmetrical fault current is 52.607 kA @ 13.8 kV with a fault point *X/R* ratio of 15.5. This results in an asymmetry factor of 1.528 or 80.361 kA asymmetrical duty. Use Equation (69) to determine the asymmetry factor. The disconnect switch has an asymmetrical withstand rating of 100.7 kA. This switch is correctly applied for the first-cycle fault duties calculated.

### 9.8.4 Motor protection fuse (4.16 kV)

Pump A motor (Bus 1B) is protected by a fuse and an overload heater. The fuse nameplate interrupting rating is 50 kA symmetrical and 3.95% of test power factor corresponding to test *X/R* of 25.

The fault point *X/R* is 6.9 which is much smaller than the fuse testing *X/R*. This means if the symmetrical fault current is less than the symmetrical rating of the fuse, the asymmetrical fault current will for certain be less than the asymmetrical rating of the fuse. In this case, the symmetrical fault current is 10.51 kA and symmetrical rating of the fuse is 50 kA, much higher than the symmetrical fault current. Therefore, the fuse is overrated from the point view of short-circuit duty evaluation.

### 9.8.5 Load center (480 V)

The secondary of load center Bus 2B has three different types of circuit breakers; the main with an instantaneous trip and high continuous current rating, the motor control center circuit breaker without an instantaneous trip and lower continuous current rating, and the data center feeder with a power circuit breaker without an instantaneous trip and the high continuous current rating. Additionally, a static load is protected by fuse. Calculated duties for these devices are listed in Table 16.

**Table 16—Duty current for low-voltage circuit breakers on Bus 2B**

| Bus | | Device | | | Interrupting duty | | | | Device capability | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ID | kV | ID | Type | CPT (Cy) | Sym. kA rms | X/R ratio | M.F. | Adj. sym. kA rms | kV | Test PF | Rated int. | Adjusted int. |
| Bus 2B | 0.480 | Fuse5 | Fuse | | 36.128 | 5.7 | 1.033 | 37.330 | 0.660 | 20.00 | 200.000 | 200.000 |
| | | CB21-1 | Molded case | | 36.128 | 5.7 | 1.033 | 37.330 | 0.480 | 20.00 | 65.000 | 65.000 |
| | | CB22-2 | Molded case | | 36.128 | 5.7 | 1.033 | 37.330 | 0.480 | 20.00 | 65.000 | 65.000 |
| | | CB24-2 | InsulUnfuse | | 36.128 | 5.7 | 1.000 | 36.128 | 0.480 | 15.00 | 65.000 | 65.000 |
| | | CB19-2- | InsulUnfuse | | 36.128 | 5.7 | 1.000 | 36.128 | 0.480 | 15.00 | 65.000 | 65.000 |
| | | Fuse6 | Fuse | | 36.128 | 5.7 | 1.033 | 37.330 | 0.600 | 20.00 | 300.000 | 300.000 |
| | | CB9 | PowerUnfuse | | 36.128 | 5.7 | 1.000 | 36.128 | 0.480 | 15.00 | 65.000 | 65.000 |

## 9.9 Equipment ground fault duty calculations

The 13.8 kV system (Bus B) given has a high ground fault current because of the solid ground condition on the generator and transformer neutrals. The ground fault current is higher than that for a three-phase fault at the bus. Therefore, the ground fault duty evaluation is required for this system.

Table 17 below provides the circuit breaker rating and duty comparison for a ground fault on phase A. Comparing Table 17 against Table 14, it can be seen that the ground fault symmetrical current at a half-cycle is 56.869 kA which is higher than the symmetrical fault current of 52.607 kA for a three-phase fault at the bus. However, as the circuit breakers at the bus are selected to have high ratings, they are still much over the short-circuit duty for a ground fault. Additionally, the ANSI standard allows the circuit breaker ground current interrupting rating to be 15% greater than the phase current provided the maximum current rating of the circuit breaker is not exceeded.

**Table 17 —Calculated single-line-to-ground fault duties compared with circuit breaker ratings (Bus B Fault)**

| Device | | Fault type, max. if phase | Momentary duty | | | | | Device capability | | |
|---|---|---|---|---|---|---|---|---|---|---|
| ID | Type | | Sym. kA rms | X/R ratio | M.F. | Asym. kA rms | Asym. kA peak | Sym. kA rms | Asym. kA rms | Asym. kA peak |
| BusB | Switchgear | AG, A | 56.869 | 15.3 | 1.525 | 86.734 | 145.913 | | 100.000 | 168.800 |
| CB:19 | 3-cycle total CB | AG, A | 56.869 | 15.3 | 1.525 | 86.734 | 145.913 | | 100.700 | 170.000 |
| CB:20 | 3-cycle total CB | AG, A | 56.869 | 15.3 | 1.525 | 86.734 | 145.913 | | 100.700 | 170.000 |
| CB:7 | 3-cycle total CB | AG, A | 56.869 | 15.3 | 1.525 | 86.734 | 145.913 | | 100.700 | 170.000 |
| CB17 | 3-cycle sym. CB | AG, A | 56.869 | 15.3 | 1.525 | 86.734 | 145.913 | | 100.700 | 170.000 |
| CB:8 | 3-cycle total CB | AG, A | 56.869 | 15.3 | 1.525 | 86.734 | 145.913 | | 100.700 | 170.000 |
| CB9 | 3-cycle total CB | AG, A | 56.869 | 15.3 | 1.525 | 86.734 | 145.913 | | 100.700 | 170.000 |
| CB1:18 | 3-cycle total CB | AG, A | 56.869 | 15.3 | 1.525 | 86.734 | 145.913 | | 100.700 | 170.000 |
| SW6 | SPST switch | AG, A | 56.869 | 15.3 | 1.525 | 86.734 | 145.913 | | 100.000 | 0.000 |
| CB:6 | 3-cycle total CB | AG, A | 56.869 | 15.3 | 1.525 | 86.734 | 145.913 | | 100.700 | 170.000 |
| CB:15 | 3-cycle total CB | AG, A | 56.869 | 15.3 | 1.525 | 86.734 | 145.913 | | 100.700 | 170.000 |

### 9.10 Capacitor switching

Circuit breakers used for capacitor switching must be able to withstand the short-circuit duties between the circuit breaker and capacitor and the transient currents that come from the capacitor when the fault is on the source side of the circuit breaker. If the size of the load capacitor bank is equal to or less than the maximum capacitor size allowed by the manufacturer on its circuit breaker, then the circuit breaker can handle the capacitor current to a fault on the source side of the breaker. The inrush current when energizing a capacitor is approximately the same as the current when de-energizing a capacitor bank into a fault. In one case, the source voltage is known and the capacitor voltage is a zero; in the second case, the internal voltage of the capacitor is known and the bus voltage is zero. If 1.0 per-unit voltage is used for either source voltages then the currents are the same. IEEE Std C37.012™-1979 covers capacitor switching in some detail.

## 10. Short-circuit calculation method and device duty per IEC standard

### 10.1 Introduction

Short-circuit calculations for industrial and commercial power systems are, as a rule, performed in North America in accordance with the ANSI standards (see Clause 8), originally introduced some decades ago. Since then, they experienced several revisions to reflect harmonization between ac/dc decrement modeling and various breaker-rating structures. To this day, they are widely accepted as an important and reliable computational tool for performing short-circuit calculations.

The purpose of this clause is to outline how short-circuit calculations are addressed by other international standards. Several fault calculation guidelines can be found worldwide, ranging from naval standards, used by shipbuilders for electrical installations on commercial and/or military vessels, to recommendations used

by engineers in several European countries. A commonly used IEC standard for this type of isolated system is IEC 61363-1 [B27]. Until the mid-1980s, one of the prevailing European standards was the German VDE-0102, covering both industrial and utility electric power systems. The work undertaken under the auspices of the International Electrotechnical Commission during the 1980s brought to fruition IEC 60909-0-4:2001 [B22], which is currently acknowledged as the accepted European standard.

Since its introduction in 1988, IEC 60909 served as platform for other international standards, such as the Australian standard AS-3851, issued in 1991. This clause will primarily focus on the IEC 60909 since it by far constitutes the main alternative to the North American ANSI standard. The treatment given here serves the purpose of providing only the most salient conceptual and computational aspects featured by the IEC 60909 standard. The user is therefore strongly advised to refer to the standard itself for further details. This clause addresses techniques pertinent to three-phase short-circuits only. The interested reader should consult the standard itself for considerations related to asymmetrical short-circuits.

## 10.2 System modeling and methodologies

The IEC 60909 standard covers three-phase ac electric power systems, operating at either 50 Hz or 60 Hz, up to voltages of 550 kV, including low-voltage systems. The standard addresses three-phase, line-to-ground, line-to-line, and double-line-to-ground short-circuits. Despite the fact that rigorous calculation techniques, such as the Helmholtz superposition method (see Figure 72) or time-domain analysis are not excluded, the IEC 60909 standard recommends the simpler equivalent source technique. The equivalent source technique assumes only one source exciting the network at the short-circuit location, while all other contributing sources are rendered inactive (see Figure 73).

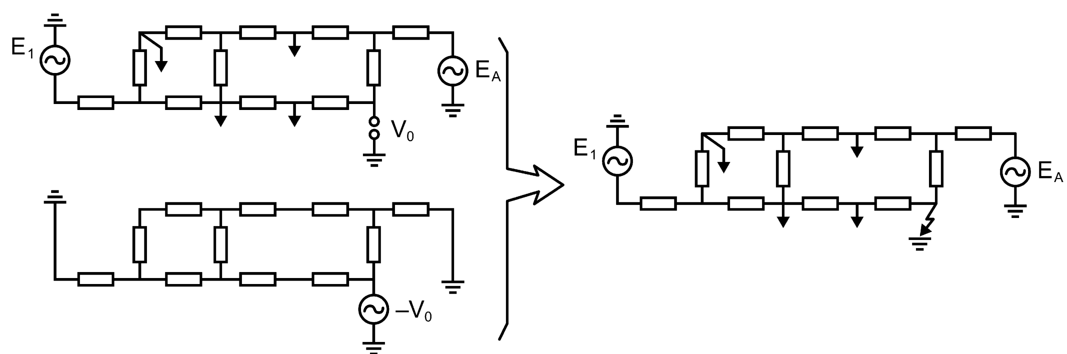



**Figure 72—The superposition analysis principle**

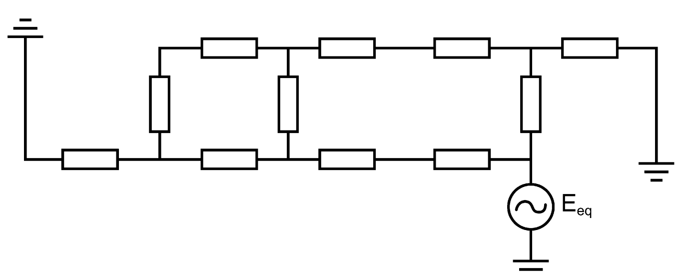



**Figure 73—The equivalent source at the fault location**

The method of symmetrical components, with explicit negative sequence representation, is used in conjunction with the equivalent voltage source at the fault location, for calculating the short-circuit currents. Since all other current sources are considered inactive, network feeders (utility interconnection points), synchronous machines, asynchronous machines, and regenerative SCR drives are represented by

their equivalent internal impedances. The magnitude of the equivalent voltage source is calculated as the product of the voltage factor *c* and the nominal system line-to-ground voltage at the fault location. System shunts (line/cable capacitances, shunt capacitors, shunt inductors) and static loads are ignored in the positive and negative sequence networks. The standard, however, recommends that line capacitances be included in the zero sequence network, if the system neutral is not solidly grounded. If the system neutral is solidly grounded, neglecting the zero sequence system shunts leads to conservative results and is not necessary to consider them. The three-phase transmission lines and cables are assumed to be balanced, with no intersequence coupling, in order to justify the use of symmetrical components. The sequence networks are reduced to equivalent impedances at the fault location for subsequent calculations. Sequence impedances for non-rotating equipment are considered equal for positive and negative sequence and transformers are, in general, to be treated with their taps in the main position.

In modeling ac decrement, IEC 60909 makes the distinction between short-circuits far from generator and short-circuits near generator. In calculating peak short-circuit currents and modeling dc decrement, the standard distinguishes whether the fault current arrives at the fault from meshed or non-meshed systems. In calculating steady-state fault currents, IEC 60909 recommends that it may be necessary to consider the excitation systems of synchronous machinery (including synchronous motors under special circumstances). All the above considerations are important and command particular calculation techniques. In what follows, the techniques for calculating maximum and minimum short-circuit currents, for all duty types, are given for the cases the standard considers as generic. The outline, notation, and sequence of presentation adopted in the standard itself has been preserved as much as possible for ease of reference. The material given here conveys only the basic computational and modeling aspects. For more details, IEC 60909 must be consulted.

## 10.3 Voltage factors

The *equivalent source* technique adopted in IEC 60909 recommends applying a voltage factor $c$ ($c_{\max}$ or $c_{\min}$ to the prefault nominal system voltage), in order to obtain the voltage magnitude of the equivalent source at the fault location. These voltage factors are reproduced, for ease of reference, in Table 18 for various voltage levels. They are important in distinguishing between maximum and minimum short-circuit currents and are introduced in order to account for prefault system loading (resulting in varying exploitation voltages), off-nominal transformer taps, excitation of generators, etc.

## 10.4 Short-circuit currents per IEC 60909

The definitions that follow have been reproduced from the IEC 60909 standard for ease of reference. The notation used by the standard has also been preserved and will be adhered to. The $I_{\max}$ and $I_{\min}$ are defined below and appropriate voltage factor, $c_{\max}$ and $c_{\min}$, as shown in Table 18, should be used when calculating them.

**Table 18 —IEC 60909 prefault voltage factors**

| Nominal voltage $U_n$ | Voltage factor $c$ for the calculation of | |
|---|---|---|
| | maximum short-circuit currents $c_{max}$[a] | minimum short-circuit currents $c_{min}$ |
| Low voltage<br>100 V to 1000 V<br>(IEC 60038, Table I) | 1.05[c]<br>1.10[d] | 0.95 |
| Medium voltage<br>> 1 kV to 35 kV<br>(IEC 60038, Table III) | 1.10 | 1.00 |
| High voltage[b]<br>> 35 kV<br>(IEC 60038, Table IV) | | |

[a] $c_{max}U_n$ should not exceed the highest voltage $U_m$ for equipment of power systems.
[b] If no nominal voltage is defined, $c_{max}U_n = U_m$ or $c_{min}U_n = 0.90 \times U_m$ should be applied.
[c] For low-voltage systems with a tolerance of + 6%, for example systems renamed from 380 V to 400 V.
[d] For low-voltage systems with a tolerance of + 10%.

**Maximum short-circuit current, $I_{max}$**—The maximum short-circuit currents are used to evaluate the interrupting and peak requirements of circuit breakers for subsequent switchgear selection and equipment rating. The appropriate voltage factor, $c_{max}$, should be used when calculating them.

**Minimum short-circuit current, $I_{min}$**—The minimum short-circuit currents are used to set the protective devices on the system and for run-up motor verification. The appropriate voltage factor, $c_{min}$, should be used when calculating them.

**Initial short-circuit current,** $I_k''$ —The rms value of the ac symmetrical component of a prospective (available) short-circuit current applicable at the instant of the short-circuit, if the system impedances remain unchanged.

**Peak short-circuit current, $i_p$**—The maximum possible instantaneous value of the prospective (available) short-circuit current.

**Symmetrical short-circuit breaking current, $I_b$**—The rms value of an integral cycle of the symmetrical ac component of the prospective short-circuit current, at the instant of contact separation of the first pole of the switching device.

**Steady-state short-circuit current, $I_k$**—The rms value of the short-circuit current which remains after the decay of the transient phenomena.

**The aperiodic component of short-circuit current, $i_{dc}$**—The mean value between the top and bottom envelope of short-circuit current decaying from an initial value to zero.

## 10.5 Short-circuits far from generator

### 10.5.1 Definitions and generalities

A short-circuit is considered to be far from generator when the magnitude of the symmetrical ac component of the prospective fault current remains essentially constant with time. This condition can be intuitively visualized as perceiving the contributing sources exhibiting constant internal voltages while their

impedances experience no change with time. In other words, short-circuits far from generator are short-circuits fed from sources which can safely be assumed to possess no ac decrement of any kind (see 10.6 for similar definitions addressing short-circuits near generator). The fault current may, nevertheless, contain an aperiodic (dc) taken into account for assessing breaker interrupting requirements and the potentially damaging mechanical effects of the short-circuit currents.

### 10.5.2 Calculation of maximum fault currents

The computational procedures given below apply only when all of the conditions stipulated in 10.5.1 are satisfied. If this is not the case, the computational techniques for faults near generator should be used. Since this section addresses calculations involving no ac decrement, the concept of the *network feeder* is introduced first.

### 10.5.3 Network feeders

Network feeders (see Figure 74) are interconnection points, usually of high supply capability, exhibiting no ac decrement characteristics, typical examples being utility service entrance points. They are to be represented, for short-circuit calculations, as impedances determined by Equation (71):

$$Z_Q = \frac{cU_{nQ}}{\sqrt{3}I''_{\mathrm{kQ}}} \tag{71}$$

where

| | |
|---|---|
| $Z_Q$ | is network feeder impedance |
| $c$ | is voltage factor at interconnection point |
| $U_{nQ}$ | is nominal system line-to-line voltage at interconnection point (kV) |
| $I''_{\mathrm{kQ}}$ | is the initial symmetrical short-circuit current at interconnection point (kA) |

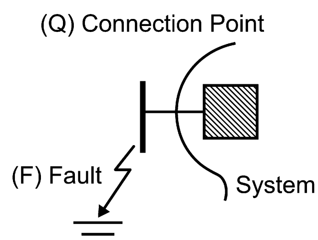



**Figure 74 —Network feeder representation**

### 10.5.4 Initial short-circuit current calculations

Assuming that the fault is fed by a single source, it suffices to calculate the total impedance to the fault $Z_k$ ($R_k + jX_k$). The initial short-circuit current $I''_k$ is then given by:

$$I''_{\mathrm{k}} = \frac{cU_{\mathrm{n}}}{\sqrt{3}Z_{\mathrm{k}}} = \frac{cU_{\mathrm{n}}}{\sqrt{3}\sqrt{R_{\mathrm{k}}^2 + X_{\mathrm{k}}^2}} \tag{72}$$

If multiple non-meshed sources feed the fault (Figure 75), Equation (72) is to be used to calculate the individual contributions to the fault. The total initial short-circuit current is then calculated as the arithmetic sum of the partial currents as follows:

$$I_{\mathrm{kt}} = I''_{\mathrm{k1}} + I''_{\mathrm{k2}} \ldots I''_{\mathrm{kn}}$$

or

$$I''_{\mathrm{k}} = \sum_{\mathrm{i}} I_{\mathrm{ki}}{}'' \tag{73}$$

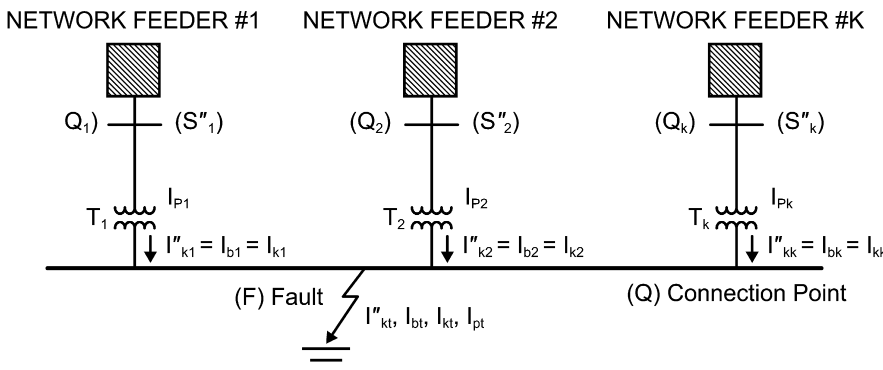



**Figure 75—Multiple-fed fault from non-meshed sources**

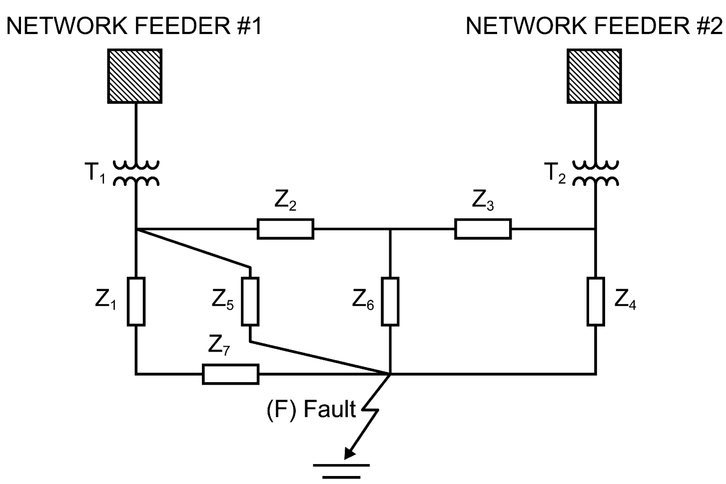



**Figure 76—Short-circuit in a meshed system**

For the more general case of meshed systems (Figure 76), the initial short-circuit is calculated using Equation (72), with $Z_k$ being the equivalent system impedance at the fault point. $Z_k$, must be calculated using complex network reduction, i.e., by considering the branch and sources complex impedances.

### 10.5.5 Symmetrical breaking current

Since no ac decrement is present for short-circuits far from generator, the initial short-circuit current remains unchanged. Thus, the symmetrical breaking current, for a single-fed short-circuit, equals the initial fault current.

$$I_{\mathrm{b}} = I''_{\mathrm{k}} \tag{74}$$

The same principle extends to the case where multiple non-meshed sources feed the short-circuit. Thus,

$$I_{\mathrm{bt}} = I_{\mathrm{b1}} + I_{\mathrm{b2}} + \ldots I''_{\mathrm{bn}} = I''_{\mathrm{k1}} + I''_{\mathrm{k2}} + \ldots I''_{\mathrm{kn}} \tag{75}$$

Equation (75) remains valid for calculating the short-circuit breaking current when the fault is fed through meshed networks of general configuration.

### 10.5.6 Steady-state fault current

Since no ac decrement is present for far from generator short-circuits, the steady-state fault current is equal to the initial fault current. Thus for single-fed short-circuits,

$$I_{\mathrm{k}} = I''_{\mathrm{k}} \tag{76}$$

for multiple fed $I_{\mathrm{kt}} = I_{\mathrm{k1}} + I_{\mathrm{k2}} + \ldots I''_{\mathrm{kn}} = I''_{\mathrm{k1}} + I''_{\mathrm{k2}} + \ldots I''_{\mathrm{kn}}$ non-meshed sources feeding the fault.

### 10.5.7 Peak fault current

IEC 60909 recommends calculating peak fault currents by applying a crest (peak) factor $\kappa$ to the symmetrical initial fault current $I''_{\mathrm{k}}$, as:

$$I_{\mathrm{p}} = \kappa\sqrt{2}I''_{\mathrm{k}} \tag{77}$$

These factors are derived under the assumption that the short-circuit occurs at zero voltage and are valid for both 50 Hz and 60 Hz systems. In order to account for ac decrement, during the rise time to peak, for faults near generators and/or motors, special *R/X* ratios are recommended for this type of equipment (see 10.6.3 and 10.7.3). Proper calculation and application of the relevant crest factor(s) necessitates distinguishing between meshed and non-meshed fault current paths as well as whether the fault is single-fed or not. A source can be considered to contribute to the fault through a non-meshed path if its contribution is independent of any remaining connections at the fault point (see Figure 75). Alternatively, a source contributes to the fault through a meshed path if its contribution is affected by other connections at the fault point (see Figure 76).

### 10.5.8 Non-meshed current paths

If the fault is single-fed, the crest factor $\kappa$ is calculated as follows:

$$\kappa = 1.02 + 0.98e - \frac{3R}{X} \tag{78}$$

where the *X/R* ratio is for the branch feeding the fault.

For the case where the fault is fed by several non-meshed sources, the technique applied to the single-fed short-circuit is applied to all individual sources feeding the fault in order to calculate the individual peak currents. The total peak current is then calculated as the sum of the partial peak currents.

$$I_{\mathrm{pt}} = I_{\mathrm{p1}} + I_{\mathrm{p2}} + \ldots I''_{\mathrm{pn}} \tag{79}$$

### 10.5.9 Meshed current paths

IEC 60909 mentions three techniques for calculating the peak short-circuit current in meshed networks, namely the following:

a) The uniform *X/R* ratio technique

b) The equivalent *X/R* ratio technique

c) The equivalent frequency technique

**The uniform *X/R* ratio technique:** For this method the factor $\kappa$ is determined from a figure and taking the smallest ratio of *R*/*X* or the largest ratio of *X*/*R* of all branches of the network.

**The short-circuit location *X/R* technique:** This technique calculates the crest factor, defined as:

$$\kappa = 1.15k_b \tag{80}$$

with $k_b$ calculated by using the *X/R* ratio of the fault impedance $Z_k$, i.e., the ratio $X_k/R_k$. It is not necessary to apply the factor 1.15 in the equation if *R/X* remains smaller than 0.3 for all branches. The factor $\kappa$ is limited to 1.8 and 2.0 for low- and high-voltage networks respectively.

**The equivalent frequency technique:** This technique calculates the crest factor, defined as:

$$\kappa_c = \kappa_a \tag{81}$$

with

$$\frac{X}{R} = \left(\frac{\mathrm{X_c}}{\mathrm{R_c}}\right)\left(\frac{\mathrm{f}}{\mathrm{f_c}}\right) \tag{82}$$

where

$R_c$ is equal to Real{$Z_c$} equivalent effective resistance component, for the frequency, $f_c$, as seen from the fault location

$X_c$ is equal to Imaginary{$Z_c$} equivalent effective reactance component, for the frequency as seen from the fault location

$f_c$ is taken to be 20 (24) Hz for a 50 (60) Hz system

$$\mathrm{Z_c} = \mathrm{R_c} + \mathrm{j}X_\mathrm{c} \tag{83}$$

$Z_c$ is the impedance seen at the fault location when the source of frequency, $f_c$, is the only source exciting the network.

### 10.5.10 Calculation of minimum fault currents

When calculating minimum fault currents, the following conditions apply:

— The voltage factor, $c_{\min}$, for the minimum fault currents is to be used.

— Select the network configuration and network feeder capacity that leads to minimum short-circuit currents. This may necessitate assuming less of the generating plant is connected to the system.

— Then impedance correction factors are equal to 1.

— Neglect motors, wind power stations, and photovoltaic power station units.

— The resistances of overhead lines and cables are to be calculated at the temperature attained at the end of the short-circuit (higher than the normally considered 20 °C) according to the formula:

$$R_{\mathrm{L}} = \left[1 + \alpha \times \left(\vartheta_e - 20\ {}^\circ\mathrm{C}\right)\right] \times R_{\mathrm{L20}} \tag{84}$$

where

$R_{\mathrm{L20}}$ is conductor resistance at 20 °C

$\vartheta_e$ is conductor temperature in °C at the end of the short-circuit duration

$\alpha$ is factor equal to 0.004/K, valid with sufficient accuracy for most practical purposes for copper, aluminum, and aluminum alloy

## 10.6 Short-circuits near generator

### 10.6.1 Definition and generalities

A short-circuit is considered to be near generator when the magnitude of the symmetrical ac component of the prospective fault current decreases with time. This condition can be perceived as viewing the internal voltages of the contributing sources remaining constant, while their impedances experience an increase in magnitude with time, at the onset of the fault. A short-circuit is considered by IEC 60909 to be near generator if at least one synchronous machine contributes a current exceeding twice its nominal current, or synchronous and asynchronous motors contribute more than 5% of the initial short-circuit current calculated without considering any motors. Additional considerations for faults near generator include impedance correction factors for the generators and their accompanying transformers (if any). For faults near generator, the steady-state fault current will normally have a smaller magnitude than the breaking current which, in turn, will have a smaller magnitude than the initial fault current. Fault currents near generator may contain an aperiodic (dc) component, which decays to zero from an initial value. This aperiodic component will have to be taken into account for assessing breaker interrupting requirements and the potentially damaging mechanical effects of the short-circuit currents.

### 10.6.2 Impedance correction factors

The impedance correction factors are used to calculate the partial short-circuit currents contributed by generators and/or power system units, while accounting for prefault loading. The IEC 60909 standard distinguishes between generator and power station correction factors, as explained below.

### 10.6.3 Generator impedance correction factor

This impedance correction factor is used when a generator is directly connected to the system, i.e., no unit transformer is found between the generator and the power system (see Figure 77). For this case the correction factor, $K_G$, is applied to the generator subtransient impedance as follows:

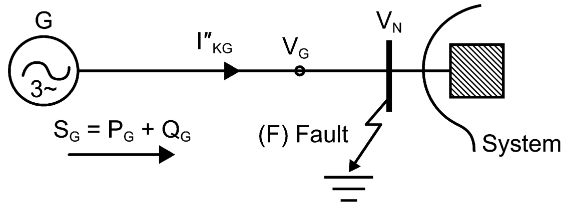



**Figure 77 —Fault on the high-voltage side of power system unit**

$$Z_{GK} = K_G \times Z_G \tag{85}$$

where

$Z_{GK}$ is the corrected generator impedance

$Z_G$ is the generator impedance

$K_G$ is the correction factor defined by:

$$K_G = \frac{U_n}{U_{rG}} \times \frac{c_{max}}{1 + X_d'' \sin \varphi_{rG}} \tag{86}$$

where

$U_n$ is the rated voltage of the system

$U_{rG}$ is the rated generator voltage

$c_{max}$ is the voltage factor at the connection point

$X_d''$ is the generator subtransient reactance in per unit of the generator rated quantities

$\varphi_{rG}$ is the generator rated power factor angle at prefault

The correction factor of Equation (86) assumes overexcited operation, $R_G \ll X_d''$ and that the generator prefault operating condition does not depart significantly from the rated one.

Typical *R/X* ratios for generator impedances, accounting for both ac and dc decrement are recommended as follows:

$R_{Gf} = 0.05X_d''$, when $U_{rG} > 1$ kV and $S_{rG} \geq 100$ MVA

$R_{Gf} = 0.07X_d''$, when $U_{rG} > 1$ kV and $S_{rG} < 100$ MVA

$R_{Gf} = 0.15X_d''$, when $U_{rG} \leq 1$ kV

The above values for the fictitious resistances $R_{Gf}$ may be used for the calculation of the peak short-circuit current with sufficient accuracy.

### 10.6.4 Power station unit correction factors

A power station unit (PSU) is a generator connected to the network through a dedicated transformer. In this case, the following impedance correction factors are recommended for power station units with on-load tap-changer:

$$\underline{Z}_{\mathrm{SK}} = \mathrm{K_S} \times \left(t_{\mathrm{r}}^2 \times \underline{Z}_{\mathrm{G}} + \underline{Z}_{\mathrm{THV}}\right) \tag{87}$$

$$\mathrm{K_S} = \frac{U_{\mathrm{nQ}}^2}{U_{\mathrm{rG}}^2} \times \frac{U_{\mathrm{rTLV}}^2}{U_{\mathrm{rTHV}}^2} \times \frac{c_{\max}}{1 + \left|x_d'' - x_{\mathrm{T}}\right| \sin \varphi_{\mathrm{rG}}} \tag{88}$$

where

$\underline{Z}_{\mathrm{THV}}$ is the impedance of the unit transformer related to the high-voltage side (without correction factor $K_T$)

$x_{\mathrm{T}}$ is the related saturated subtransient reactance of the unit transformer at the main position of the on-load tap-changer: $x_{\mathrm{T}} = \dfrac{X_{\mathrm{T}}}{\left(\dfrac{U_{\mathrm{rT}}^2}{S_{\mathrm{rT}}}\right)}$

$t_{\mathrm{r}}$ is the related transformation ratio of the unit transformer: $t_r = \dfrac{U_{\mathrm{rTHV}}}{U_{\mathrm{rTLV}}}$

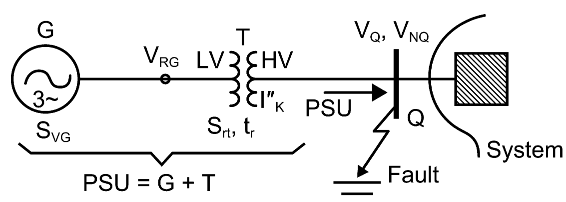



**Figure 78—Power system unit with transformer**

For short-circuits on the high-voltage side of a power station unit without on-load tap-changer (see Figure 78), a different correction factor is recommended. The correction factor for the power system unit (PSU) is:

$$\underline{Z}_{\mathrm{SOK}} = K_{\mathrm{SO}} \times \left(t_{\mathrm{r}}^2 \times \underline{Z}_{\mathrm{G}} + \underline{Z}_{\mathrm{THV}}\right) \tag{89}$$

where

$\underline{Z}_{\mathrm{SOK}}$ is the corrected PSU impedance without on-load tap-changer

$K_{\mathrm{SO}}$ is PSU impedance correction factor

$t_{\mathrm{r}}$ is rated unit transformer voltage ratio $t_{\mathrm{r}} = \dfrac{U_{\mathrm{rTHV}}}{U_{\mathrm{rTLV}}}$

$\underline{Z}_{\mathrm{G}}$ is generator subtransient impedance referred to HV side

$\underline{Z}_{\mathrm{THV}}$ is rated unit transformer impedance referred to HV side (without correction factor $K_{\mathrm{T}}$)

$$K_{\mathrm{SO}} = \frac{U_{\mathrm{nQ}}}{U_{\mathrm{rG}}\left(1+p_{\mathrm{G}}\right)} \times \frac{U_{\mathrm{rTLV}}}{U_{\mathrm{rTHV}}} \times \left(1 \pm p_{\mathrm{T}}\right) \times \frac{c_{\max}}{1+x_{\mathrm{d}}'' \sin \varphi_{\mathrm{rG}}} \quad (90)$$

where

$U_{\mathrm{rTHV}}$ is the rated unit transformer voltage (high-voltage side)

$U_{\mathrm{rTLV}}$ is the rated unit transformer voltage (low-voltage side)

$1 \pm p_{\mathrm{T}}$ is the consideration for unit transformer with off-load taps and if one of these taps is permanently used

Equation (90) is not conditional upon whether the generator was overexcited or underexcited before the short-circuit.

Note that in case of unbalanced short-circuits, Equation (90) shall be applied to the positive, negative, and zero sequence impedances of the power station unit.

### 10.6.5 Calculation of generator maximum initial fault currents

The initial short-circuit currents are to be calculated as in the case of short-circuits currents far from generation. The impedance correction factors for generators and/or power station units must be taken into account.

### 10.6.6 Calculation of generator peak short-circuit currents

Peak fault currents are to be calculated in the same fashion as for the case of short-circuits far from generation. The distinctions made earlier between single-fed and multiple-fed short-circuits and on whether the fault path is meshed or non, apply here as well. The generator and/or power station unit impedances used, must take properly into account the pertinent correction factors as in the case of the initial fault currents.

### 10.6.7 Calculation of generator symmetrical breaking currents

The decay of a generator symmetrical short-circuit current, for a fault at its terminals, is quantified by virtue of the factor $\mu$ as follows:

$$I_b = \mu I''_{\mathrm{kmax}} \quad (91)$$

where

$I_b$ is the symmetrical breaking current at time $t$

$I''_{\mathrm{kmax}}$ is the initial short-circuit current

$\mu$ is the decrement factor, to time $t$ defined as:

$$\mu = 0.84 + 0.26\mathrm{e}^{\frac{-0.26 I''_{\mathrm{kG}}}{I_{\mathrm{rG}}}} \quad \text{for } t_{\min} = 0.02\ \mathrm{s} \quad (92)$$

$$\mu = 0.71 + 0.51\mathrm{e}^{\frac{-0.30 I''_{\mathrm{kG}}}{I_{\mathrm{rG}}}} \quad \text{for } t_{\min} = 0.05\ \mathrm{s}$$

$$\mu = 0.62 + 0.72e^{\frac{-0.32 I''_{kG}}{I_{rG}}} \quad \text{for } t_{min} = 0.10 \text{ s}$$

$$\mu = 0.56 + 0.94e^{\frac{-0.38 I''_{kG}}{I_{rG}}} \quad \text{for } t_{min} = 0.25 \text{ s}$$

where

$I_{rG}$ is the rated generator current

$t_{min}$ is the minimum time delay

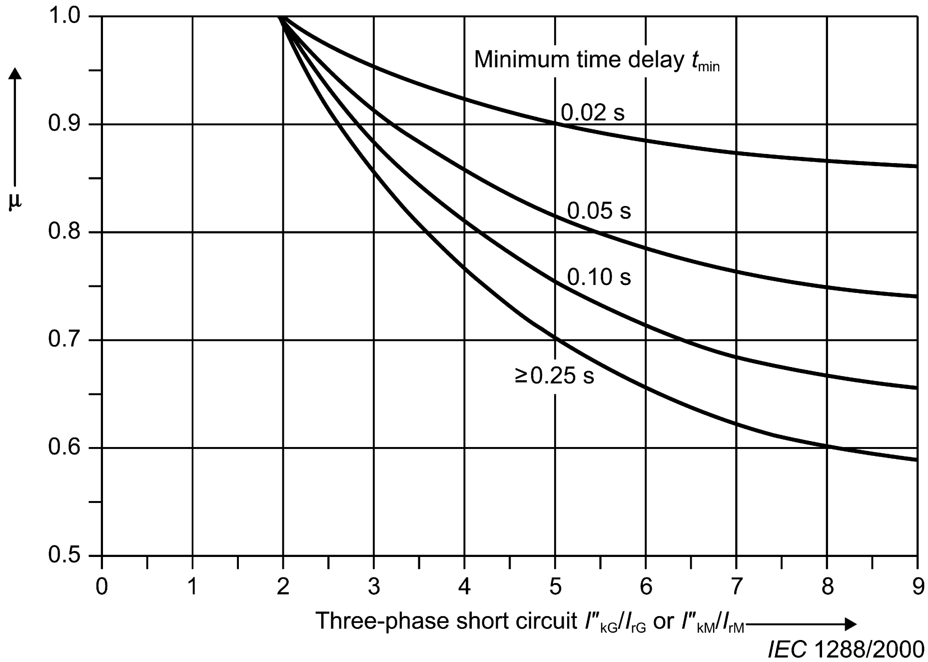



**Figure 79—Factor $\mu$ for the calculation of short-circuit breaker current $I_b$**

Figure 79 can be used also for compound excited low-voltage generators with a minimum time delay $t_{min}$ not greater than 0.1 s.

In Equation (93) if the ratio $\frac{I''_{kG}}{I_{rG}}$ is less than 2, the factor $\mu$ is taken to be equal to 1 for all parting times.

Interpolation can be used to predict the decrement factor $\mu$ for times other than the tabulated ones. Equations (92) apply to turbo alternators, salient pole generators, and synchronous compensators excited by either rotating or static converters (converters with a minimum time delay of less than 0.25 seconds and with maximum excitation voltage not exceeding 1.6 times the corresponding rated load voltage). For all other cases, $\mu$ is to be taken as 1.0. If the fault is fed by more than one synchronous generator in parallel, the total breaking current is the sum of the individually contributed breaking currents. For a fault fed by several generators in a meshed network, as a first approximation, lack of ac decrement can be assumed by stipulating that the breaking current is equal to the initial short-circuit current. The calculation is thus reduced to calculating the initial short-circuit current $I''_{kG}$ at the fault location of interest. An alternative calculation technique entails extending the notions of ac decrement modeling, applied for faults at terminals, by considering machine proximity to the fault.

### 10.6.8 Steady-state fault currents calculation

Steady-state fault current estimates depend on machine synchronous reactances, saturation influences, effectiveness of voltage regulation, and maximum excitation voltage. Note that the procedures given below are considered reasonably accurate for the case of one generator supplying the short-circuit. Normally, the steady-state fault current is of less magnitude than the initial and/or the breaking currents. However, when several generators are present in the system, one should always be mindful of the possibility that one or more machines may fall out of step during a sustained short-circuit. In extreme cases, the steady-state fault current may, in fact, turn out to be of a magnitude higher than the initial short-circuit current. The same procedures can be applied to the case of a synchronous motor feeding the fault, assuming that the motor excitation system is independently fed. The steady-state short-circuit current, if the fault is fed from a meshed network, can be taken to be equal to the initial short-circuit current, with the motor contributions neglected (IEC 60909-0-4:2001 [B22]).

### 10.6.9 Maximum steady-state fault current, $I_{kmax}$

$$I_{kmax} = \lambda_{max} \times I_{rG} \tag{93}$$

where

| | |
|---|---|
| $I_{kmax}$ | is the maximum steady-state fault current |
| $\lambda_{max}$ | is scaling coefficient |
| $I_{rG}$ | is generator rated current |

This is the steady-state fault current, furnished by a generator, for a fault at its terminals, taking into account voltage regulator action.

The maximum steady-state fault current is related to the generator rated current by virtue of its thermal effects. Since synchronous reactances and excitation systems are quite different in turbo-alternators and salient pole machines, the scaling coefficient max depends on the following:

a) Whether the machine is of turbo or salient-pole construction

b) The maximum possible excitation voltage produced by the excitation system

### 10.6.10 Minimum steady-state fault current, $I_{kmin}$

This current, being of interest to the selection and setting of protective devices is the steady-state fault current provided by the generator, for a fault at its terminals, when constant no load excitation is assumed under no voltage regulator action. It is calculated as follows:

$$I_{kmin} = \lambda_{min} \times I_{rG} \tag{94}$$

where

| | |
|---|---|
| $I_{kmin}$ | is the minimum steady-state fault current |
| $\lambda_{min}$ | is scaling coefficient |
| $I_{rG}$ | is generator rated current |

The scaling coefficient $\lambda_{min}$ depends only on whether the machine is of the turbo alternator or salient-pole construction.

### 10.6.11 The coefficients $\lambda_{max}$ , $\lambda_{min}$

The values of the coefficients $\lambda_{max}$ and $\lambda_{min}$ are obtained from curves, which are included in Figure 80 and Figure 81 the standard. Two groups of curves are provided, one group for turbo alternators and another group for salient-pole machines. In turn, every group contains two sets of curves, the series 1 set and the series 2 set. The curves for series 1 $\lambda_{max}$ are based on the highest possible excitation-voltage, referred to the excitation voltage at rated operation (rated current under rated power factor). They are derived for 1.3 times the rated excitation for turbo alternators and 1.6 times the rated excitation for salient pole machines (IEC 60909-0-4:2001 [B22]). The curves for series 2 $\lambda_{max}$ are based on the highest possible excitation-voltage, again referred to the excitation voltage at rated operation. They are derived for 1.6 times the rated excitation for turbo alternators and 2.0 times the rated excitation for salient-pole machines (IEC 60909-0-4:2001 [B22]).

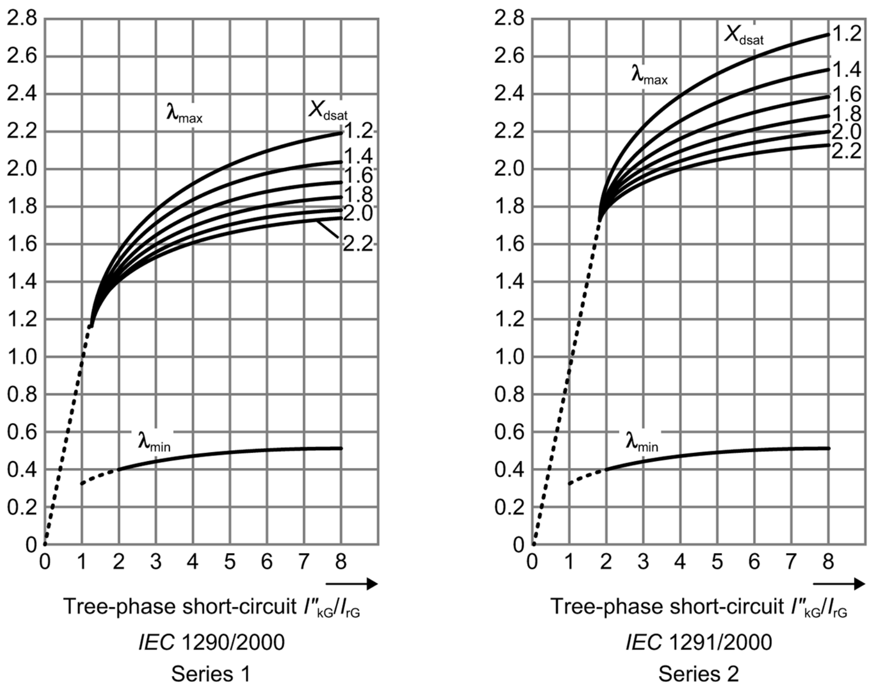



**Figure 80 —Factors $\lambda_{max}$ and $\lambda_{min}$ for cylindrical rotor generators**

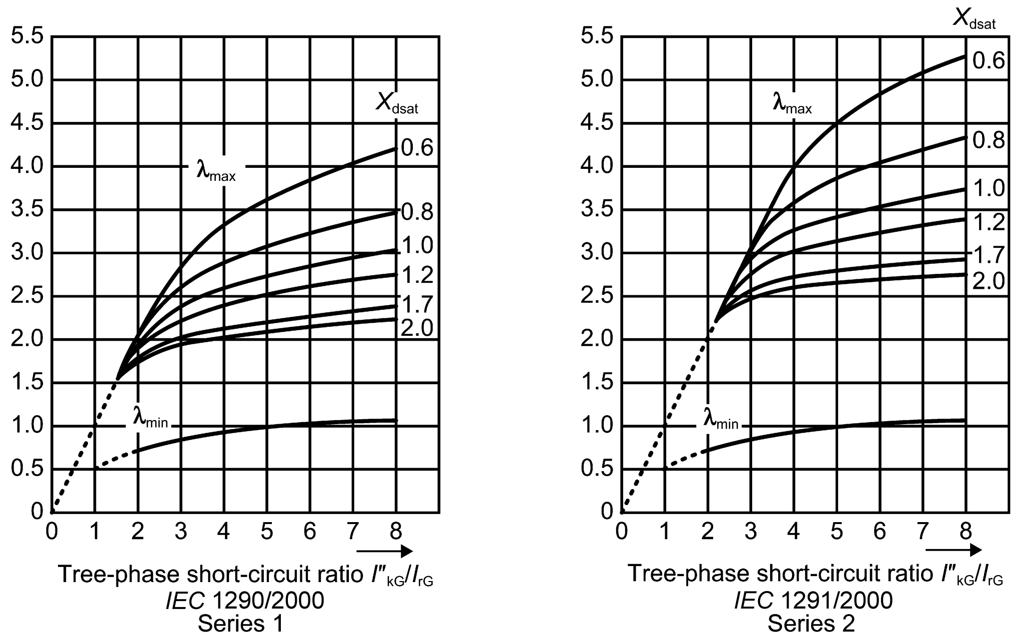



**Figure 81 —Factors $\lambda_{max}$ and $\lambda_{min}$ for salient-pole machines**

## 10.7 Influence of the motors

### 10.7.1 General considerations

For faults, near generator motor contributions are to be considered when calculating the short-circuit currents. Asynchronous motor plant contributions, for a given fault location, can be neglected if the rated current of the contributing motor(s) does not exceed 5% of the fault current, and is calculated without considering any motors (IEC 60909-0-4:2001 [B22]). These considerations rest on quantifying induction motor contributions and apply to either directly connected motors or to motors connected through transformers. Note that these considerations do not, generally, apply to three-winding transformers (IEC 60909-0-4:2001 [B22]). In what follows, calculation techniques for induction and synchronous motor contributions are briefly discussed.

### 10.7.2 Synchronous motors

Synchronous motors and synchronous compensators are to be treated as synchronous generators when calculating the initial and peak short-circuit currents. For the case of the steady-state fault currents, this is applicable only if the synchronous motors' exciters are not bus-fed. The same will apply to synchronous compensators. When breaking currents are calculated, synchronous motor ac decrement is quantitatively modeled as in generators (see Equation (91)). The ratio r is, however, replaced by the ratio m, which in this case is the ratio of the short-circuit current at the terminals of the motor $I''_{m}$ to the rated motor current $I_{rm}$.

### 10.7.3 Asynchronous motors

The impedance $\underline{Z}_M = R_M + jX_M$ of asynchronous motors is given by:

$$Z_M = \frac{1}{\frac{I_{LR}}{I_{rM}}} \times \frac{U_{rM}}{\sqrt{3} \times I_M} = \frac{1}{\frac{I_{LR}}{I_{rM}}} \times \frac{U_{rM}^2}{S_{rM}} \tag{95}$$

where

$U_{rM}$ is motor rated voltage

$I_{rM}$ is motor rated current

$I_{LR}$ is motor locked-rotor current

$S_{rM}$ is motor rated apparent power

The complex impedance value of the motor can be calculated by:

$$\underline{Z}_M = R_M + jX_M = \left(\frac{R_M}{X_M} + j\right) \times \frac{Z_M}{\sqrt{1 + \left(\frac{R_M}{X_M}\right)^2}} \tag{96}$$

If $R_M/X_M$ is known, then $X_M$ can be calculated as follows:

$$X_M = \frac{Z_M}{\sqrt{1 + \left(\frac{R_M}{X_M}\right)^2}} \tag{97}$$

If $R_M/X_M$ is not provided by manufacturers:

For high-voltage motors with power per pair of poles higher or equal to 1 MW,

$$\frac{R_M}{X_M} = 0.10, \text{ with } X_M = 0.995\ Z_M$$

For high-voltage motors with power per pair of poles less than 1 MW,

$$\frac{R_M}{X_M} = 0.15, \text{ with } X_M = 0.989\ Z_M$$

For low-voltage motors with connection cables,

$$\frac{R_M}{X_M} = 0.42, \text{ with } X_M = 0.922\ Z_M$$

### 10.7.4 Static drives

Static fed regenerative SCR drives are modeled as asynchronous motors with:

— $Z_M$: According to Equation (95).

— $U_{rM}$: Converter transformer rated voltage on network side or drive rated voltage in the absence of transformer.

— $I_{rM}$: Converter transformer rated current (network side) or drive rated current in the absence of transformer.

— $\frac{I_{LR}}{I_{rM}} = 3.0$ and $\frac{X_M}{R_M} = 10.0$ with $X_M = 0.995\ Z_M$

## 10.8 Fault calculations in complex systems

### 10.8.1 Introduction

In the preceding sections, fault current calculation techniques and methodologies were outlined for several generic system topologies. When carrying out calculations for a more complex system, a combination of the above cases is generally encountered. For instance, the short-circuit current may contain not only generator and network feeder contributions, but also substantial motor (synchronous and asynchronous) content with varying degrees of electrical proximity to the fault location. The situation may be further complicated, from a topology point of view, by the fact that several of these sources may feed the fault through a network portion, comprising many branches, while others may be directly connected to the short-circuit location. Generally speaking, a combination of the above-stated computational techniques should be used to avoid relaxing several binding clauses of the IEC 60909 standard.

### 10.8.2 Example system

This subclause shows a simplified IEC example system. The system as shown in Figure 82 has two utility service entrance points at 13.8 kV, with a fault level of 100 MVA and 50 MVA, respectively. Customer power supplies are from buses Sub 2A and Sub 2B through transformers TR:3 and TR:4. The tie breaker 9A2 is normally open.

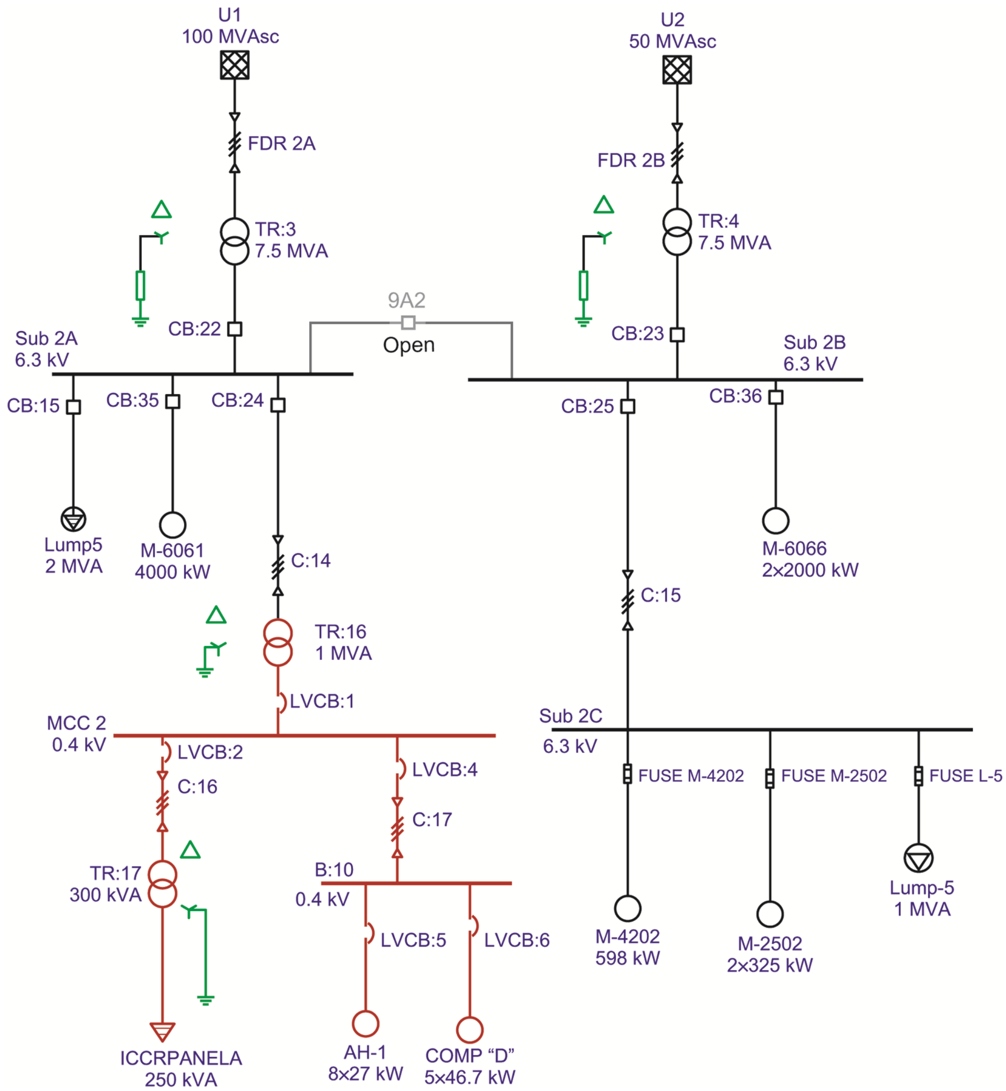



**Figure 82—Simplified IEC sample system**

### 10.8.3 Calculation of fault currents based on IEC 60909

Based on IEC 60909, fault currents are calculated for fault types: three-phase, line-to-ground, line-to-line, and line-to-line-to-ground. The calculation should include initial fault current $I''_k$, peak fault current $i_p$, breaking current $I_b$, and steady-state fault current $I_k$.

Figure 83 shows a summary report for bus Sub 2A and bus Sub 2B.

**Short-Circuit Summary Report**

3-Phase, LG, LL, LLG Fault Currents

| Bus | | 3-Phase Fault | | | Line-to-Ground Fault | | | | Line-to-Line Fault | | | | *Line-to-Line-to-Ground | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ID | kV | I"k | ip | Ik | I"k | ip | Ib | Ik | I"k | ip | Ib | Ik | I"k | ip | Ib | Ik |
| Sub 2A | 6.300 | 8.566 | 20.319 | 4.379 | 0.219 | 0.520 | 0.219 | 0.219 | 7.495 | 17.780 | 7.495 | 7.495 | 7.549 | 17.907 | 7.549 | 7.549 |
| Sub 2B | 6.300 | 6.795 | 15.969 | 2.926 | 0.219 | 0.515 | 0.219 | 0.219 | 5.662 | 13.306 | 5.662 | 5.662 | 5.719 | 13.439 | 5.719 | 5.719 |

All fault currents are in rms kA. Current ip is calculated using Method C.

* LLG fault current is the larger of the two faulted line currents.

**Figure 83—Sample summary report**

More detailed reports should be provided respectively for three-phase, line-to-ground, line-to-line, and line-to-line-to-ground faults. Figure 84 shows the line-to-ground short-circuit report for bus Sub 2A.

**SHORT- CIRCUIT REPORT**

Fault at bus : **Sub 2A**

Nominal kV = 6.300 Voltage c Factor = 1.10 (User-Defined)

**Line-To-Ground Fault**

| Contribution | | % Voltage at From Bus | | | | | | Current at From Bus (kA) | | | | | | Sequence Current (kA) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| From Bus | To Bus | Va | | Vb | | Vc | | Ia | | Ib | | Ic | | | | |
| ID | ID | Mag. | Ang. | Mag. | Ang. | Mag. | Ang. | Mag. | Ang. | Mag. | Ang. | Mag. | Ang. | I1 | I2 | I0 |
| Sub 2A | Total | 0.00 | 0.0 | 171.62 | -150.7 | 174.10 | 149.2 | 0.219 | -1.4 | 0.000 | 0.0 | 0.000 | 0.0 | 0.073 | 0.073 | 0.073 |
| 820 | Sub 2A | 0.00 | 42.5 | 171.62 | -150.7 | 174.10 | 149.2 | 0.005 | 11.6 | 0.002 | -143.9 | 0.003 | 172.5 | 0.003 | 0.002 | 0.000 |
| 45 | Sub 2A | 97.01 | 29.7 | 97.50 | -90.0 | 97.75 | 149.6 | 0.147 | -2.8 | 0.036 | 0.3 | 0.036 | 2.5 | 0.037 | 0.037 | 0.073 |
| M-6061 | Sub 2A | 105.00 | 0.0 | 105.00 | -120.0 | 105.00 | 120.0 | 0.050 | 2.3 | 0.025 | 178.6 | 0.025 | -173.8 | 0.024 | 0.026 | 0.000 |
| Lump5 | Sub 2A | 105.00 | 0.0 | 105.00 | -120.0 | 105.00 | 120.0 | 0.018 | -3.8 | 0.009 | 177.3 | 0.009 | 175.2 | 0.009 | 0.009 | 0.000 |
| MCC 2 | 820 | 105.73 | -30.7 | 104.36 | -150.6 | 105.24 | 90.0 | 0.005 | 11.6 | 0.002 | -143.9 | 0.003 | 172.5 | 0.003 | 0.002 | 0.000 |
| Bus1 | 45 | 97.07 | 29.7 | 97.50 | -90.0 | 97.78 | 149.6 | 0.030 | -3.8 | 0.000 | -90.1 | 0.030 | 175.5 | 0.017 | 0.017 | 0.000 |

\# Indicates fault current contribution is from three-winding transformers
* Indicates a zero sequence fault current contribution (3I0) from a grounded Delta-Y transformer

**Figure 84—Sample line-to-ground short-circuit report**

### 10.8.4 Calculation of fault currents for protective device capability

Protective device capability can be evaluated based on IEC 60909 short-circuit calculation. All the protective devices connected to a bus should be evaluated with either the total bus fault current or protective device maximum through fault current.

Figure 85 shows a summary report for protective devices of Sub 2A and Sub 2B. Note that in this case the bus total fault currents are used to evaluate the circuit breaker capabilities.

**Short-Circuit Summary Report**

3-Phase Fault Currents

| Bus | | Device | | Device Capacity (kA) | | | | Short-Circuit Current (kA) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Making | | | | | | | | | |
| ID | kV | ID | Type | Peak | Ib sym | Ib asym | Idc | I"k | ip | Ib sym | Ib asym | Idc | Ik |
| Sub 2A | 6.300 | Sub 2A | SwtchGear | | | | | 8.566 | 20.319 | | | | 4.379 |
| | 6.300 | CB:22 | CB | 63.000 | 25.000 | 28.050 | 12.721 | 8.566 | 20.319 | 7.198 | 7.518 | 2.168 | |
| | 6.300 | CB:24 | CB | 63.000 | 25.000 | 28.050 | 12.721 | 8.566 | 20.319 | 7.198 | 7.518 | 2.168 | |
| | 6.300 | CB:35 | CB | 63.000 | 25.000 | 28.050 | 12.721 | 8.566 | 20.319 | 7.198 | 7.518 | 2.168 | |
| | 6.300 | CB:15 | CB | 63.000 | 25.000 | 28.050 | 12.721 | 8.566 | 20.319 | 7.198 | 7.518 | 2.168 | |
| Sub 2B | 6.300 | Sub 2B | SwtchGear | | | | | 6.795 | 15.969 | | | | 2.926 |
| | 6.300 | CB:23 | CB | 63.000 | 25.000 | 28.050 | 12.721 | 6.795 | 15.969 | 5.373 | 5.539 | 1.347 | |
| | 6.300 | CB:25 | CB | 63.000 | 25.000 | 28.050 | 12.721 | 6.795 | 15.969 | 5.373 | 5.539 | 1.347 | |
| | 6.300 | CB:36 | CB | 63.000 | 25.000 | 28.050 | 12.721 | 6.795 | 15.969 | 5.373 | 5.539 | 1.347 | |

ip is calculated using method C
Ib does not include decay of non-terminal faulted induction motors
Ik is the maximum steady state fault current
Idc is based on X/R from Method C and Ib as specified above

LV CB duty determined based on service rating.
Total through current is used for device duty.
* Indicates a device with calculated duty exceeding the device capability.
# Indicates a device with calculated duty exceeding the device marginal limit. ( 95 % times device capability)

**Figure 85—Sample summary report for protective devices**

A more detailed short-circuit report should be provided. Figure 86 shows the breaking and dc current report for bus Sub 2A.

**Breaking and DC Fault Current (kA)**

**Based on Total Bus Fault Current**

| TD (S) | Ib sym | Ib asym | Idc |
|---|---|---|---|
| 0.01 | 8.215 | 11.541 | 8.106 |
| 0.02 | 8.092 | 9.917 | 5.734 |
| 0.03 | 7.779 | 8.722 | 3.944 |
| 0.04 | 7.411 | 7.892 | 2.714 |
| 0.05 | 7.060 | 7.352 | 2.053 |
| 0.06 | 6.894 | 7.042 | 1.439 |
| 0.07 | 6.731 | 6.806 | 1.009 |
| 0.08 | 6.573 | 6.611 | 0.708 |
| 0.09 | 6.420 | 6.439 | 0.496 |
| 0.10 | 6.271 | 6.283 | 0.390 |
| 0.15 | 5.964 | 5.964 | 0.070 |
| 0.20 | 5.674 | 5.674 | 0.013 |
| 0.25 | 5.404 | 5.404 | 0.002 |
| 0.30 | 5.383 | 5.383 | 0.000 |

**Figure 86—Sample breaking and dc current report**

## 10.9 Low-voltage systems

Low-voltage systems (i.e., not exceeding 1 kV) are classified according to their earthing connection. The typical nomenclature and related definitions used in IEC, as per Mitolo, Tartaglia, and Panetta [B54] and IEC 60364-4-41: 2005 [B20] are shown in Table 19.

**Table 19 —IEC nomenclature**

| Abbreviation | Definition |
|---|---|
| ECP | Exposed conductive part, i.e., conductive enclosure of electrical equipment |
| EXCP | Extraneous conductive part |
| PE | Protective conductor |
| PEN | Neutral wire acting also as protective conductor |
| TT | Solidly grounded power system; ECPs directly connected to ground, independently of the grounding of any point of the power system |
| TN | Solidly grounded power system; ECPs directly connected to the grounded point of the power system (e.g., neutral point) |
| TN-S | Same definition as TN; PE is separate from the neutral conductor |
| TN-C-S | Same definition as TN; PE and neutral are combined in a single conductor in a part of the system |
| IT | Ungrounded, or high resistance grounded, power system; ECPs are grounded independently of the power source |
| $R_N$ | Ground grid/ground electrode resistance at the supply transformer (it is not an intentional resistance) |
| $R_U$ | Ground electrode resistance at the user panel (it is not an intentional resistance) |
| Direct contact | Contact with parts normally live |
| Indirect contact | Contact with conductive parts normally not energized, but likely to become live upon faults (e.g., enclosures of equipment) |

### 10.9.1 TT systems

TT (terre-terre) systems are defined as the electrical systems whose ECPs are connected to earth independently of the ground electrodes of the source (e.g., the local utility) (Figure 87).

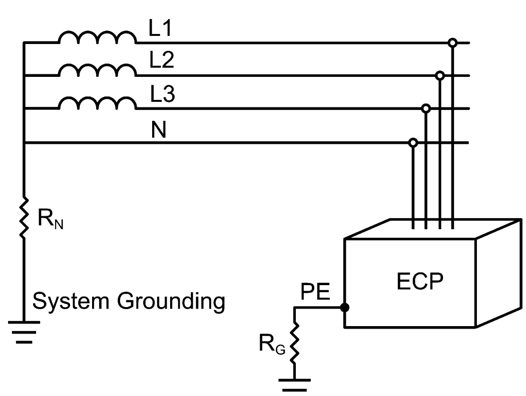



**Figure 87 —TT systems**

$R_N$ represents the resistance to ground of the earth electrode of the source.

This is the earthing method adopted for low-voltage systems supplying dwelling units in several countries, among which are: Algeria, Belgium, Denmark, Egypt, France, Greece, Italy, Japan, Kenya, Luxemburg, Morocco, Tunisia, Spain, Portugal, Turkey, United Arab Emirates, etc.

In this earth arrangement, the fault current travels through the earth, and is limited by the earth resistances $R_N$ at the utility source, and $R_G$ at the user (Figure 87). A reduced fault current renders unlikely the operation of overcurrent protective devices within a safe time, as it is substantiated later on.

TT users must install and maintain a grounding system at their premises. A major difference between IEC standards and the U.S. National Electrical Code (NEC) concerns the permitted types of ground electrodes. Whereas the NEC allows metal underground water pipes of proper dimension to act as earth electrodes, (IEC 60364-4-41: 2005 [B20]) prohibits their use in several countries, such as Austria, Belgium, Finland, France, Germany, Sweden, Switzerland, and the United Kingdom; in Italy, a water pipe system can be used as an electrode only with the consent of the water utility. In Germany, in new construction there is the obligation to erect a foundation earth electrode.

As anticipated, in the case of single line-to-ground (SLG) faults, the current $\underline{I}_G$ returns to the source by travelling through the actual earth. Its magnitude, therefore, is limited by the series of the earth resistances $R_N$ and $R_G$. Overcurrent devices can protect against indirect contact if the following condition is fulfilled, as per IEC 60364-4-41: 2005 [B20]:

$$I_G = \frac{U_0}{Z_{Loop}} \geq I_a$$

$Z_{Loop}$ is the magnitude of the fault loop impedance as composed by the source, the line conductor up to the point of the fault, the user's ground $R_G$, and the utility ground $R_N$. $R_G$ is generally the largest element in the loop. $U_0$ is the nominal voltage between line and the neutral conductors. $I_a$ is the current that causes the tripping of the over-current protective device within the safe time specified.

### 10.9.2 TN system

TN (terre-neutral) systems are defined as the electrical systems whose ECPs are directly connected by a protective conductor to the solidly grounded point of the source (e.g., the neutral point) (Figure 88).

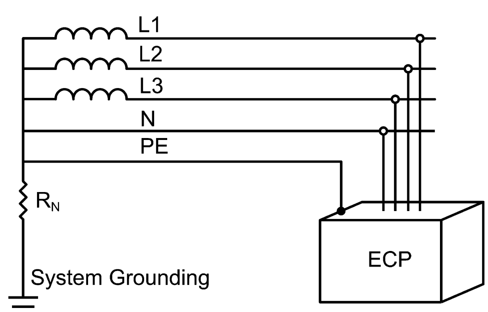



**Figure 88—TN-S systems**

$R_N$ represents the resistance-to-ground of the earth electrode of the source. The different arrangements of neutral and protective conductors determine three types of TN system. In TN-S systems (Figure 88), two separate wires are used as protective and neutral conductors throughout the system.

In TN systems the ground fault current $\underline{I}_G$ returns to the source via the protective conductor PE and unlike in TT systems, will not circulate through the ground. For this reason, the ground fault current is a short-

circuit current, in terms of magnitude. Protective overcurrent devices, therefore, will trip and protect against indirect contact, if the following condition is fulfilled, as per IEC 60364-4-41: 2005 [B20]:

$$I''_{k1min} = \frac{U_0}{Z_{Loop}} \geq I_a$$

### 10.9.3 Calculation of $I''_{k1min}$

With reference to Figure 89, we can calculate the impedance $Z_Q$ of the high-voltage network as:

$$Z_Q = \sqrt{R_Q^2 + X_Q^2}$$

The apparent short-circuit power of the high-voltage network, as communicated by the utility, is given by:

$$S''_{kQ} = \frac{c3U_1^2}{Z_Q}$$

where $U_1$ is the phase-to-neutral tension of the high-voltage network.

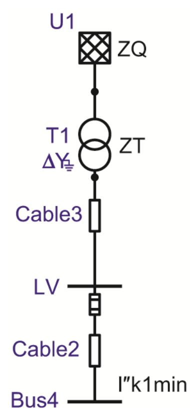



**Figure 89—Calculation of $I''_{k1min}$**

In order to calculate the low-voltage single-phase ground fault current, the impedance $Z_Q$ needs to be transferred to the secondary side of the transformer $T_1$. Thus:

$$Z_{Q2} = Z_Q \frac{U_{20}^2}{U_1^2} = \frac{3U_{20}^2}{S''_{kQ}}$$

The minimum single-phase ground fault current can be calculated as follows:

$$I'_{k1min} = \frac{U_{02}}{\sqrt{\left(R_{Q2} + R_T + 2 \times l \times R'_L\right)^2 + \left(X_{Q2} + X_T + 2 \times l \times X'_L\right)^2}}$$

where

$R_T$ is the resistance of the transformer

$X_T$ is the reactance of the transformer

$R'_L$ is the resistance per-unit length of conductors

$X'_L$ is the reactance per-unit length of conductors

$l$ is the length of conductor to the point of fault (half the fault loop length)

When calculating minimum short-circuit currents, the resistances $R_L$ of lines (i.e., overhead lines and cables, line conductors, and neutral conductors) must be introduced at a higher temperature, per the following formula (IEC 60909-0-4: 2001 [B22]):

$$R_L = \left[1 + \alpha\left(\theta_e - 20\ °C\right)\right] R_{L20}$$

where

$R_{L20}$ is the resistance at a temperature of 20 °C

$\theta_e$ is the conductor temperature in degrees Celsius at the end of the short-circuit duration[10]

$\alpha$ is a factor equal to 0.004/K, applicable with sufficient accuracy for most practical purposes for copper, aluminum, and aluminum alloy

### 10.9.4 IT system

IT (isolation terre) systems are defined as those systems whose source is isolated from ground, or connected to it through a sufficiently high impedance (e.g., rated neutral grounding resistor rated 5 A). In this arrangement, it is advisable to avoid, although not forbidden, shipping the neutral wire to loads, in order to safeguard its isolation from ground.

In the event of a first fault between a line conductor and an ECP, or earth, fault currents can still flow, due to the distributed capacitance to ground of the electrical system. Such currents are relatively low in intensity, but may be sufficient to cause harmful touch voltages over faulted enclosures. Thus, in order to limit such hazards, ECPs are required to be earthed individually (Figure 90), in groups, or collectively.

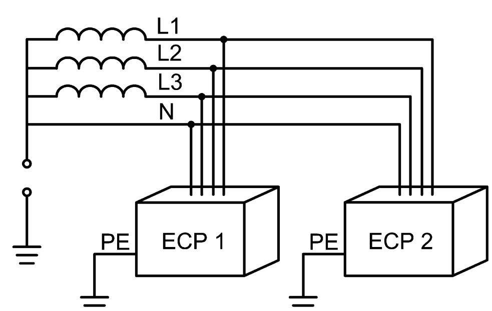



**Figure 90—ECPs earthed individually in IT system**

As a result, if touch voltages are kept below 50 V (IEC 60364-4-41: 2005 [B20]), the disconnection of supply as a protection against indirect contact is neither required, nor necessary for safety.

[10] For values for $\theta_e$, see IEC 60865-1, IEC 60949, and IEC 6098.

After a first SLG fault, which practically earths the system, a second SLG fault, involving a different phase conductor, may occur. The IT system becomes a TT or TN, depending on how the ECPs are grounded (i.e., individually, in groups, or collectively). Accordingly, the safety requirements for either TT or TN systems must be met.

# 11. Comparison of ANSI and IEC short-circuit calculation methods

## 11.1 Introduction

By comparing the ANSI and IEC standards for short-circuit calculations, one can clearly see that the two differ from each other, from modeling of equipment to calculation methods. One common question from electrical engineers is, Which one tends to provide more conservative results? There is no general answer to this question, since it depends on the electrical system under consideration. It should be pointed out that as both calculation methods are based on approximate models, choosing the method that provides the largest short-circuit current in the system is not very relevant. This is because one of the main purposes of short-circuit calculations is, in fact, to size, or verify, ratings of equipment. The selected short-circuit current calculation method must be in compliance with the standard upon which the equipment has been manufactured.

Although significant effort has been made to harmonize rating structure for higher voltage circuit breakers in the new standard, the rating structure and testing requirements for bus, circuit breakers, fuse, switch, etc., are not quite in agreement between ANSI and IEC standards. These standards are created to go hand in hand with the corresponding standards for equipment ratings. Therefore, if a system contains equipment in compliance with ANSI standards, then the ANSI standard short-circuit calculation method must be selected to evaluate this equipment. This is also true for the equipment in compliance with IEC standards.

## 11.2 Difference in equipment modeling

In ANSI short-circuit calculations, equipment impedance values are mainly based on parameters provided by manufacturers, with certain tolerance applied to achieve conservative fault current values. In IEC short-circuit calculations, a correction factor is applied to synchronous machines and transformers to account for normal operating conditions.

**Machine modeling—**According to ANSI and IEC standards, all machines are modeled by a constant voltage source behind an impedance. The two methods differ in how the machine impedance is utilized. In ANSI short-circuit calculation, induction machine impedance is calculated based on motor locked-rotor impedance multiplied by a factor, defined as the ANSI multiplication factor. The ANSI multiplication factor is applied to take into account machine operating conditions and effects of motor feeder cable and overload heater, and its value varies depending on machine size and speed. The synchronous machine impedance is based on parameters provided by manufacturers. It should be noted that when performing device duty calculation for generator circuit breakers per IEEE Std C37.013™-1997, a detailed synchronous generator model must be used, which includes machine sub-transient and transient impedance and time constant to accurately account for machine ac and dc decays.

In IEC short-circuit calculations, the impedance of synchronous generator and compensator is adjusted by a factor ($K_G$) to account for prefault operating condition and excitation of the machine. If a generator is a part of a power station unit, a different adjustment factor is used. For induction motors, the locked-rotor impedance is used in the calculation without any adjustment.

**Transformer modeling—**In ANSI, the transformer impedance values by the manufacturer are used in the calculation. To take into account the possible inaccuracy of these parameters, when they are not obtained from field testing of actual equipment, additional impedance tolerance may apply. In IEC, an impedance correction factor ($K_T$) is applied to transformer impedance to take into account prefault operating conditions, including transformer taps. The correction factor $K_T$ is calculated differently based on the transformer being a network transformer or a power station unit transformer.

## 11.3 Difference in calculation method

**Prefault voltage**—Calculated short-circuit currents are proportional to prefault voltages. Even though both ANSI and IEC methods apply flat internal voltage for all contribution sources and recommend to ignore prefault operating currents, the prefault voltage used in short-circuit calculations is different between the two methods. The ANSI short-circuit calculation applies maximum operating voltage, ranging from 100% to 105% of individual system, whereas IEC short-circuit calculation uses a c factor multiplied by the bus nominal voltage. The IEC 60909 standard specifies the range of the c factor for different voltage levels, 1.1 being the maximum value for all voltage levels.

**AC short-circuit component decay**—AC decrement modeling is conceptually and computationally different in the two standards. ANSI favors a universal machine reactance adjustment for calculating the symmetrical interrupting currents. For induction machines and synchronous motors, the decay of ac short-circuit contributions is modeled by different machine reactance values for the first and 1.5- to 4-cycle system networks. For synchronous generators, depending on the electrical distance from the machine to the fault location (measured by the ratio of the machine contribution to the fault over the short-circuit current when the machine terminals are faulted), different multipliers specified in the standard are applied on short-circuit current when performing device duty evaluation. Additionally, the ac decay in ANSI short-circuit is calculated independently of actual protective device parting time.

IEC 60909 recommends, instead, to take into account the machine proximity to the short-circuit, the system configuration, and explicitly includes the parting time. With respect to a given fault location, the system configuration and source contributions can be classified as single-fed short-circuit, short-circuit on non-meshed network, and short-circuit on meshed network. IEC 60909 basically requires that the short-circuit contributions from different sources be calculated separately for a fault location, based on the classification of the source with respect to the fault location. For a far-from-generator short-circuit, ac decay is neglected. For a near-to-generator short-circuit, the ac decay is calculated based on the breaking time, machine size, and its short-circuit contribution to the fault.

In summary, the ANSI method provides a more systematic approach, whereas the IEC method offers more detailed modeling.

**DC short-circuit component decay**—DC decrement modeling is conceptually and computationally different in the two standards as well. ANSI favors a single approach, based on the *X/R* ratio at the fault point, featuring separate reactance and resistance reductions of the faulted network. IEC 60909 considers system configurations with respect to a fault location in calculating dc short-current decay as well, and suggests three different methods for E/X calculations.

**Steady-state current**—Steady-state fault current calculations are different in the two guidelines due to the fact that IEC requires explicit consideration of synchronous machinery excitation systems and saturation influences. The steady-state current is equal to the generator rated current multiplied by a factor, which is a function of excitation type and ratio short-circuit current over rated current. ANSI standard does not expressly specify how to calculate steady-steady short-circuit current. A general practice is to ignore all motors and use $X'_d$ to represent synchronous generator reactance.

**Generator circuit breaker evaluation**—IEEE Std C37.013-1997 is designated to the calculation method for generator circuit breakers, due to larger dc rating of the circuit breaker and the larger *X/R* ratio of short-circuit current from generator when its terminal is faulted. The method requires detailed generator modeling to account for dc and ac decay of the short-circuit current.

IEC 60909 has special sections to handle modeling of power station unit generators and transformers to account for special operating conditions of such units. The adjustment factor is also calculated differently depending on the fault location, whether at the source side of the transformer, or between the generator and the transformer.

The ANSI method offers much more accurate calculation results.

**Effect of network configuration on short-circuit calculation**—ANSI short-circuit calculations provide a systematic approach for all types of system configurations, either radial or looped systems. This does simplify the calculation procedure.

IEC standards offer different approaches for ac and dc decay for single-fed, radial, and meshed systems. Note that this classification is with respect to a given fault location. While providing more accurate modeling methods, it may sometimes cause confusion, as there is no clear reason why a radial system should be treated so differently from meshed systems. In a radial system, there can be some branches that carry short-circuit current from several sources and, therefore, in such a case the decay of ac and dc short-circuit contributions from these sources cannot be calculated independently.

These generic differences in system modeling and computational requirements render the IEC 60909 standard more computationally intensive than its ANSI counterpart. Differences in the results between the two standards are to be expected, with the IEC 60909 providing more conservative results.

If computer simulations are to be performed, the different computational techniques and database requirements of the two standards warrant the use of dedicated software.

# 12. Equipment data required for short-circuit calculation

## 12.1 Introduction

One of the most time consuming and critical items required in a short-circuit analysis is obtaining available data. The less data that is assumed, the better and more accurate the results. There are conditions when most of the data may initially have to be estimated, such as when designing a new system. As the system becomes finalized, specific equipment data may be available and the results are more pertinent. On existing systems, the amount of estimated data are greatly reduced.

An up-to-date one-line diagram is needed. If one is not available, site inspection is required to determine switchgear and load center connection points. There may be cases where no information exists regarding the interconnection of plant loads back to the utility supply. The lack of information is usually the result of a temporary “quick fix” that never properly became documented and over time became permanent. A time-consuming tracing of conductors is required to identify its connection to a known point. Therefore, one great value of the short-circuit study is an up-to-date one-line diagram.

In the discussion below, the available data, used for short-circuit calculations that can be obtained from equipment nameplates, is noted by *. Other data required will have to be itemized and requested or gathered separately. The data are then converted to ohms or per-unit ohms before it can be used in the analysis.

## 12.2 Utility sources

The equipment impedance data for utility sources must be obtained from the utility company. When requesting such information, it is very important to specify clearly the location point of the utility source contribution, base voltage used for the calculation, *X/R* ratio at the point specified, and fault types (three phase and/or line to ground). A one-line diagram sketch is often helpful in defining the point of the equivalent. Most utilities do not include the industrial user as a source of short-circuit current unless in-plant generation is present. In addition, the equivalent source impedance will be from a complex $R$ + jX calculation. Generally, the source impedance from neither a separate $R$ and $X$ ($R_{\text{only}}$ and $X_{\text{only}}$) nor first-cycle and interrupting-time calculations will be available. When one set of impedances is furnished by the utility, it is generally assumed to be the maximum short-circuit value or the first-cycle value. If the plant has more than one connection point, then a more complex equivalent is required and part of the utility may have to be represented. Typical forms of the data received from the utility are given below:

a) MVA with phase angle or *X/R* ratio (requires voltage level, in that MVA was calculated)

b) Fault current with phase angle or *X/R* ratio (requires voltage level, in that current is calculated)

c) Resistance and reactance in ohms (requires voltage level, in that ohms are calculated)

d) Per-unit resistance and reactance (requires voltage level and MVA base, usually 100 MVA)

e) Percent resistance and reactance (requires voltage level and MVA base, usually 100 MVA)

To conduct unbalanced short-circuit calculations, the negative and zero sequence impedance of the utility is also required. In general, the negative sequence impedance of a utility is assumed to be equal to positive sequence impedance. The zero sequence impedance values must be provided, or calculated based on the line-to-ground short-circuit current. Sometimes the line-to-ground fault values of a utility are given as the short-current MVA instead of the actual current values. It should be noted that the line-to-ground short-circuit MVA is considered as $\text{kV}_{\text{ln}} \times \text{kA}_{\text{scLG}}$, the line-to-neutral voltage multiplied by fault current. However, the short-circuit MVA for the line-to-ground fault provided by the utility company is often equal to $\sqrt{3} \times \text{kV}_{\text{ll}} \times \text{kA}_{\text{scLG}}$, the three-phase MVA value with current equal to the line-to-ground short-circuit.

If there is a main transformer at the power grid connection point, it needs to be clear that the short-circuit rating provided by the utility company is the value for a fault at the secondary side of the transformer and the effect of the transformer is included in the power grid short-circuit rating. If this is not the case, the transformer must be expressly modeled in the system study.

## 12.3 Generators

The data available from the machine nameplate is not significantly complete for an accurate short-circuit calculation. Typical data on the nameplate are as follows:

- Manufacturer and serial number
- Rated MVA*, voltage*, and power factor
- Rated frequency and machine speed
- Rated current and field voltage

The machine nameplate data required for short-circuit calculations are noted by an *. While some of the above data are useful, the machine impedances, if furnished, are supplied on a separate data sheet. If this data sheet is not available, the manufacturer can usually provide the data required if the serial number is available. These data may have to be recalculated or extracted from the original drawings at a cost to the user. On machines built in the early 1900s, the subtransient impedance was defined differently from what it

is today. A recalculation by the vendor could result in different impedance values as compared to what was originally furnished. The following data are required for short-circuit calculations:

a) $X''_{dv}$—Rated voltage (saturated) direct-axis subtransient reactance (first-cycle and interrupting calculations)

b) $X'_{dv}$—Rated voltage (saturated) direct-axis transient reactance (relaying time calculations)

c) $X_{2v}$—Rated voltage (saturated) negative sequence reactance (used to calculate $X/R$ ratio, and in unbalanced fault calculations)

d) $T_{a3}$—Rated voltage generator armature time constant in seconds, or $R_a$—armature resistance, (used to calculate $X/R$ ratio)

e) Short-circuit current decrement curve, including curves with voltage regulator action (excitation filed forcing) and without voltage regulator response (field current held constant) (Note: not required, but will be useful in relaying time calculations)

f) $X_0$—Zero sequence reactance (used in unbalanced fault calculations for grounded generators)

One item not supplied as part of the generator nameplate or data sheet that may be required for relaying time calculations is the type of voltage regulator used with the generator.

## 12.4 Synchronous motors

The data required for synchronous motors are the same as that furnished for generators. Machine nameplate data may not be sufficiently complete for an accurate short-circuit analysis. Typical data on the nameplate are:

- Manufacturer and serial number
- Rated MVA*, voltage*, and power factor
- Rated frequency and machine speed
- Rated current and field voltage

The machine nameplate data required for short-circuit calculations are noted by an *. While some of the above data are useful, the machine impedances, if available, are given on a separate data sheet. If a data sheet is not available, the manufacturer can usually provide the data required if the serial number is available. These data may have to be recalculated or extracted from the original drawings at a cost to the user. Some manufacturers may only furnish one transient or subtransient impedance for motors, that is usually the rated voltage $X''_{dv}$ value that is desired for short-circuit calculations. The following data are required for short-circuit calculations:

a) $X''_{dv}$—Rated voltage (saturated) direct-axis subtransient reactance (first-cycle and interrupting calculations)

b) $X'_{dv}$—Rated voltage (saturated) direct-axis transient reactance (relaying time calculations)

c) $X_{2v}$—Rated voltage (saturated) negative sequence reactance (used to calculate $X/R$ ratio and unbalanced faults)

d) $T_{a3}$—Rated voltage generator armature time constant in seconds, or $R_a$—armature resistance, (used to calculate $X/R$ ratio)

e) Short-circuit current decrement curve (not required, but may be useful in relaying time calculations)

f) $X_0$—Zero sequence reactance (used in unbalanced fault calculations for grounded motors; most wye-connected motors are not connected to system neutrals)

One item not supplied as part of the motor nameplate or data sheet that may be required for relaying time calculations is the type of voltage regulator used with the motor.

## 12.5 Induction motors

Some data required for short-circuit studies that include induction motors is on the motor nameplate. But the nameplate data are not sufficiently complete for an accurate short-circuit calculations. Typical data on the nameplate are as follows:

a) Manufacturer and serial number

b) Rated HP or MVA* and voltage*

c) Rated frequency and motor speed*

d) Rated current and NEMA code letter* or locked-rotor current

Data required for short-circuit calculations are noted by an *. Machine impedances are seldom furnished on a separate data sheet. However, if a data sheet is available, the manufacturer usually specifies the locked-rotor current that can be used to estimate the motor subtransient impedance. More detailed impedance data are available at a cost, but is usually not justified. Different impedance data are furnished for the motor at both stall and running conditions and the resistances furnished may not include the one required for short-circuit calculations. The motor starting reactance is most often used for short-circuit calculation. However, the resistance to be used for short-circuit calculations is lower than the starting resistance provided on the data sheet.

Data for smaller motors is usually estimated because the cost of obtaining this information is not justified.

## 12.6 Transformers

Transformer nameplates usually provide most of the data required for short-circuit calculations. Typical data on the nameplate are as follows:

a) Manufacturer and serial number

b) Rated MVA* and frequency

c) Rated primary and secondary voltages*

d) Rated current and taps available*

e) Transformer percent impedance* (NOTE—For systems where transformers are being newly purchased, it is recommended that the specified factory testing requirements include impedance and load-loss determinations at the tap extremes, in addition to the nominal rated voltage tap.)

f) Number of windings, winding connection, and phase relationship* (needed for unbalanced fault calculations)

g) Manufacturer test report

The nameplate data required for short-circuit calculations are noted by an *. Note that the transformer nameplate data are given as a percent impedance and not percent reactance and is generally given on the self-cooled rating unless otherwise specified. The reactance is determined once the percent resistance is known. The transformer *X/R* ratio is not on the nameplate, but can be determined from the transformer test

sheet or losses, if provided. Some data sheets do provide the percent resistance as a piece of data, otherwise, the percent resistance (%$R$) is determined by the following equations:

$$\%R = \frac{(\text{total watt loss - no load loss}) \times 100}{\text{transformer rating in volt amperes}}$$

or

$$\%R = \frac{(\text{full load winding loss}) \times 100}{\text{transformer rating in volt amperes}}$$

The standard phase relationship of a delta-wye or wye-delta transformer is that the high-voltage (HV) side leads the low-voltage (LV) side by 30° for positive phase sequence systems. When performing unbalanced fault calculations, the positive sequence current and voltage shifts by either + 30° or –30°, while the negative sequence current and voltage have the same phase shift but in the opposite direction. Note that one side of the transformer is selected as reference. With the reference established, the phase shift is applied following the general rule of "HV side leads LV side for positive sequence, and HV lags LV for negative sequence." As an example, suppose that a delta-wye transformer has the HV winding selected as reference. Based on this choice of reference, the positive sequence LV side values will lag the positive sequence HV side values, and the negative sequence LV side values will lead the negative sequence HV side values. The signs on the phase shifts would be exactly reversed if the LV side were selected as reference and the HV side values were required to be shifted with respect to the LV side values. There will be no shift of the zero sequence current since there is no path for this current component to flow. The zero sequence voltage is determined by the zero sequence impedance times the zero sequence current flow on each side of the transformer.

## 12.7 Reactors

The reactor nameplate usually provides most of the data required for short-circuit calculations. Typical data on the nameplate are as follows:

a) Manufacturer and serial number
b) Rated voltage* and frequency
c) Rated current* and taps available*
d) Reactor percent impedance*
e) Reactor ohms* (not always provided)
f) Percent voltage drop* (not always provided)
g) Manufacturer test report

The nameplate data required for short-circuit calculations are noted by an *. The reactor $X/R$ ratio is not on the nameplate, but can be determined from the reactor test sheet or losses, if provided. Some data sheets do provide the reactance, the resistance, and reactor Q factor as a piece of data. Not all the above * items can be used directly for a short-circuit calculation. For example, the percent impedance is on the through kVA (volts × amperes) of the reactor and for a three-phase reactor the through kVA is:

$$\text{Through kVA} = \sqrt{3} I_{Rated} V_{Rated,LL}$$

The impedance can also be determined from the voltage drop as follows:

$$\text{Impedance in ohms} = \frac{\text{volt drop in volts}}{I_{Rated}}$$

The base for the percent voltage drop (when used) is line-to-line rated voltage.

For a three-phase reactor the self kVA is:

$$\text{Self kVA} = 3I^2_{Rated}X$$

In order to maintain steady-state system operating voltages within acceptable voltage balance tolerances, it is often necessary to specify a compensated reactor design for air-core, current-limiting reactors where the three-phase coils of the reactor are vertically stacked over each other. Due to the mutual inductance effects of current flowing through all three phases, the reactor coil physically located at the center will have significant flux linkages from both the top and bottom reactor coils, effectively increasing its inductance. The center reactor coil is compensated by being wound with a fewer number of turns than the other two, effectively making its self-inductance lower. For balanced three-phase load or fault currents, this compensation will equalize the phase reactances and the voltage drops resulting from the phase current flow. If the system is solidly grounded, the compensation will result in a higher current for a line-to-ground fault associated with the center phase. However, most industrial power system neutrals are resistance grounded, and therefore the ground fault current is limited by the neutral resistor and this effect is not relevant.

## 12.8 Capacitors

The inclusion of capacitor data are usually not necessary under most conditions. If inclusion of the capacitor data are required, the capacitors nameplate is complete for short-circuit calculations. The data on the nameplate will be as follows:

a) Manufacturer and serial number
b) Rated voltage* and frequency
c) Rated kvar*

The nameplate data required for short-circuit calculations are noted by an *. The capacitor $X/R$ ratio is not on the nameplate, but is generally very high and can be determined from the capacitor loss test sheet, if it is provided. If assuming the $X/R$ ratio, a value from 200 to 300 should be acceptable, because the series cable resistance quickly overwhelms the capacitor resistance. The length of cable to the capacitor bank is important and should be included.

## 12.9 Static regenerative drives

The inclusion of static regenerative drive data will be necessary in the first-cycle calculations. (Note that non-regenerative drives are not sources of fault current and need not be considered.) The rectifier transformer and drive motor size is required. Typical data on the drive transformer nameplate are as follows:

a) Manufacturer and serial number
b) Rated voltage* and frequency
c) Rated primary and secondary voltages*
d) Rated current and taps available*

e) Transformer percent impedance*

f) Number of windings, winding connection, and phase relationship

The nameplate data required for short-circuit calculations are noted by an *. The drive transformer *X/R* ratio is not on the nameplate, but can be determined from the transformer test sheet or losses, if provided. Some data sheets do provide the percent resistance as a piece of data, otherwise, the percent resistance (%*R*) is determined by the following equations:

$$\%R = \frac{\left(\text{total watt loss - no load loss}\right)\times 100}{\text{transformer rating in volt amperes}}$$

or

$$\%R = \frac{\left(\text{full load winding loss}\right)\times 100}{\text{transformer rating in volt amperes}}$$

Note that the drive transformer nameplate data are given as a percent impedance and not percent reactance. The reactance is determined once the percent resistance is known.

The size of the driven motor load is also required to determine the short-circuit current contribution or equivalent source impedance. The motor size may have to be extracted from drawings. The motor data needed is the same as given for motors in 12.4 and 12.5. For short-circuit calculations where the drive is modeled as an induction motor, the equivalent drive impedance should be greater than the typical impedance of an induction motor with the same rating.

## 12.10 Circuit breakers, contactors, and current transformers

The inclusion of circuit breaker, contactor, or current transformer impedances is seldom done in short-circuit calculations. These impedances are more significant in low-voltage system analysis than for the higher-voltage systems. The impedances of series connected trip or thermal overload devices in the power circuit on low-voltage systems can greatly reduce the available fault current downstream from such devices, and therefore should be included when required. For fractional horsepower motor loads, the thermal overload devices will have an impedance magnitude in ohms as compared to cable impedances in milliohms.

## 12.11 Cables

The connecting cables will not have any impedance data stamped on them. Data typically found on the cable include the following:

— Manufacturer

— Rated voltage*

— Type of cable* and insulation type*

— Size of conductor*

In addition, the following data are required:

— Length

— Type of cable construction (1/C or 3/C)

— Number of cables in parallel and physical spacing

— Type of cable duct used (steel, fiber, cable tray, direct burial, etc.)

Data shown on cable and required for short-circuit calculations are noted by an *. The impedance data per unit of length must be determined from other sources, such as manufacturer's literature or general cable impedances in texts. The cable manufacturer's literature is preferred because insulation thickness may differ between manufacturers; whereas most references provide typical impedance values (see Beeman [B6], IEEE Std 141-1993 [B31], IEEE Std 242-2001 [B34], Stevenson [B60]). References usually provide positive sequence impedance that is used in three-phase faults. For unbalanced faults, the zero sequence cable data are required and not usually provided in references.

The zero sequence impedances of cables differ from that of the positive and negative sequence and depends on the physical configuration and the impedances of the ground return paths. Formulas for calculating cable impedances are available in many books, such as *Elements of Power System Analysis* [B60].

## 12.12 Transmission lines

The impedance data for connecting transmission lines should be based on the line configuration. Drawings or sketches showing wire size, type of conductor material, and conductor spacing are required. In addition, circuit length, type and size of ground wire, and earth resistance must be obtained.

The impedance data per unit of line length will have to be determined from other sources, such as *Elements of Power System Analysis* [B60] or the *Electrical Transmission and Distribution Reference Book* [B66].

## 12.13 Protective device ratings

Protective device ratings include: closing and latching capability of high-voltage circuit breakers, interrupting capability of high-voltage circuit breakers, low-voltage circuit breakers and fuses, as well as bus bracing capability for switchgear and motor control centers. These protective devices ratings do not affect system short-circuit calculation results. But as a standard feature of all software for power system analysis, these ratings will be compared against appropriate system short-circuit duty values per relevant standards.

When specifying protective device rating values into a software program, the user should pay attention to the rating values required by the program and those provided from manufacturer data sheets. For example, bus bracing value can be specified as the peak value, asymmetrical value, and symmetrical value, depending on the voltage level of the bus. In case the values required do not match the equipment data sheet, the user must convert the values from data sheets to the ones required by the software.

The interrupting current rating of high-voltage and low-voltage circuit breakers varies depending on the operating voltage. When specifying interrupting rating for circuit breakers, it is important that the correct rating values for the operating voltage are specified. For high-voltage circuit breakers, manufacturers provide a rated interrupting value corresponding to the maximum voltage. For ANSI high-voltage circuit breakers, most computer programs calculate interrupting rating for the specified operating voltage value based on IEEE Std C37.10 [B48]. For certain low-voltage circuit breakers, several interrupting rating values can be provided by manufacturers. For example, a circuit breaker with maximum voltage rating at 600 V can have different interrupting ratings at 600 V, 480 V, and 277 V. It is important to specify the correct interrupting rating value for the short-circuit studies.

# 13. Data collection and preparation

## 13.1 Introduction

The data required for performing system short-circuit calculations may be obtained with different methods, depending on the type and stage of the studies. If the study is for an existing system, the equipment parameters should be coming from equipment nameplate, manufacturer data sheet, design document, or field testing results. If the study is for the conceptual design of a future system, generally typical data will be used.

## 13.2 Utility short-circuit parameters

Utility (power grid) is the most important short-circuit contributing source to a short-circuit fault, especially at medium- and high-voltage level. Therefore it is very important to obtain accurate parameters for the utility. The utility parameters can only be obtained from the utility company which has electrical connections with local systems. Due to variation in utility operating conditions, it is preferred to obtain utility short-circuit parameters for maximum and minimum contributions for both three-phase and single-phase faults. The maximum short-circuit contribution parameters will be used to size/evaluate system equipment rating, while the minimum short-circuit contribution parameters will be used to protective device settings.

## 13.3 Equipment data from existing system

### 13.3.1 Introduction

If the short-circuit study to be conducted is for an existing system, all parameters required for various types of equipment should be, as much as possible, obtained from the nameplate of equipment, manufacturer-provided data sheet, and testing results of the actual equipment. Even though sometimes the nameplate data and the manufacturer-provided data sheet may be for a class of equipment and is not guaranteed 100% accurate, they are still more accurate than the typical data provided by some computer software or standards.

Typical data or library data provided by computer software may also be used for studies of existing systems. This is normally the case for a system that has been around for many years and it is difficult to locate the manufacturer-provided data sheet. Additionally, it is time consuming or not feasible to obtain all equipment data based on nameplate or manufacturer data sheet, especially for less-important equipment, such as a small motor or static load. In these cases, typical data can also be used.

### 13.3.2 Nameplate and manufacturer data sheet

For recently built systems, it should not be difficult to obtain nameplate, manufacturer data sheet, or system design document. It includes:

a) Generation unit

b) Synchronous motor

c) Induction motor

d) Bus bars, switchgear, switchboard, and panel board

e) Transformer

f) Transmission line and cable

g) Protective devices, such as circuit-breaker, fuse, and switch

### 13.3.3 Field test data

Test data sheet provides the most accurate representation of equipment. It should be used whenever it is available. Due to additional costs involved, field tests are conducted only on equipment with large ratings, which has significant effects on short-circuit results. Sometimes equipment manufacturers may also provide field testing data if such tests are requested at time of purchasing. The types of equipment that may have test data include:

a) Transformer

b) Generator

c) Large synchronous or induction motor

### 13.3.4 Field measurement

Depending on the purpose of short-circuit calculations, some field measurement data may also be needed for short-circuit calculation, as the operating conditions can also affect short-circuit calculation results. These operating parameters include:

a) Bus operating voltage value, including maximum voltage, minimum voltage and normal operating voltage. Note that short-circuit current is proportional to system prefault voltage.

b) System loading conditions, including maximum loading and minimum loading conditions. Note that a highly loaded system condition generally indicates that more motors are in operation. This means more short-circuit contribution from system loads and moderate bus voltages.

c) System configurations, including operating status of switching devices i.e., circuit breaker, switches, contacts, etc.

## 13.4 Typical data for short-circuit calculation

In many cases, the nameplate and manufacturer’s data sheet are not available, such as studies for conceptual design of a new system. In these cases, using typical data becomes the only option. Sometimes even for studies of an existing system, typical data can become handy or necessary, as it takes time and effort to collect all parameters for all equipment. Some computer software provides typical data for various equipment. Generally typical data can be obtained from different sources. Some of them are summarized below:

a) Manufacturer published data, such as cable, line, protective devices, etc.

b) Standards such as IEEE, NEC, NEMA, and IEC regarding transformers, electric motors, protective devices, etc.

c) Reputable publications, such as engineering manuals and professional books, trade papers and magazines, etc.

### 13.5 Library data from computer software

Library data is a collection of manufacturer-published data sheets or typical data provided by a computer software. A good computer software for power system analysis must have a library with extensive data. Since even for studies of an existing system, it would be an impractical task to obtain all required data from nameplates or manufacturer data sheets for all equipment, such as lines, cables, small motors, and protective devices. It is almost in all cases, that to a certain extent, library data provided by the computer software will be utilized for conducting system studies. Equipment parameters supplied by a power system analysis software should include the following:

a) Transmission line and cable

b) Transformer

c) Generator

d) Synchronous and induction motor

e) Protective devices, such as circuit breaker, fuse, switch, etc.

## 14. Model and data validation

### 14.1 Introduction

Model and data validation is the most important task to be carried out before any system calculations can be conducted. The accuracy of simulation results from any software cannot be better than the accuracy of its input data and the models used to represent system equipment. From this point view, the significance of model and data validation cannot be overstressed.

### 14.2 Parameters and model to be validated

All the parameters affecting short-circuit calculation results should be validated; from short-circuit contributing elements, power transmission components, to prefault system operating conditions. In general, all equipment parameters described in Clause 12 should be validated.

a) Short-circuit contributing sources—They include power utility, synchronous generator, synchronous motor, induction motor, and equivalent lump load. The rating parameters and sequence impedance values of these components must be closely checked and validated. If generator circuit breakers are to be evaluated, details of synchronous machines models need to be validated.

b) Power transmission equipment—It includes transformers, transmission lines, cables, reactors, and equivalent impedance components. Equipment parameter tolerance values should also be validated, such as transformer impedance tolerance and length tolerance of lines and cables. These tolerance values are used to account for uncertainty in equipment parameters.

c) Prefault operating parameters—These include system configurations and operating voltage values.

d) Protective device rating parameters—These include circuit-breakers, fuse, switch, contact, etc. The parameters of protective device does not affect short-circuit results. However, these ratings are used in comparison against short-circuit results in device rating studies. It is important to make sure that the correct rating values are being evaluated.

In general, methods used in short-circuit calculation for a quality computer software should follow related standards. As users, we only need to select the correct short-circuit standard to perform studies.

### 14.3 Methods for model and data validation

There are several methods that can be used to validate model and data for short-circuit studies:

a) Check against the data source, including nameplate and manufacturer data sheet. Data entry errors can often occur, especially for a larger system. Having a second, or even third pair of eyes validate data entry can save time for the whole project.

b) Validate, based on engineering common sense or rule of thumb. After data entry has been completed, run several quick short-circuit calculations and check the results based on engineering common sense. It can help to spot modeling mistakes. For example, in ANSI short-circuit calculations, if interrupting current at a bus becomes larger than the momentary current, it indicates that there are mistakes in machine impedance data entry.

## 15. Study scenarios and solution parameters

### 15.1 Introduction

From system design, maintenance, and operation point view, different study scenarios need to be considered. Most extreme cases, such as maximum and minimum possible short-circuit current contributions, need to be under consideration. Short-circuit current contributions can be affected by source/load operating level, system configuration, and system devices.

### 15.2 Maximum and minimum short-circuit contributions

#### 15.2.1 Introduction

Without considering different system configuration and device effect, maximum and minimum short-circuit current contributions depend on short-circuit source operating level and system impedance.

#### 15.2.2 Maximum contributions

To consider maximum short-circuit current contribution the following usually are applied:

a) Maximum contribution from sources (power grid, generator, and so on)

b) Maximum negative adjustment for branch (cables, transmission lines, and so on) length

c) Maximum negative adjustment for branch (transformer and so on) impedance

d) Maximum negative adjustment for resistance temperature correction (cable and transmission line)

e) Maximum motor load contributions

### 15.2.3 Minimum contributions

To consider minimum short-circuit current contribution, the following usually are applied:

a) Minimum contribution from sources (power grid, generator, and so on)

b) Minimum negative/positive adjustment for branch (cables, transmission lines, and so on) length

c) Minimum negative/positive adjustment for branch (transformer and so on) impedance

d) Minimum negative/positive adjustment for resistance temperature correction (cable and transmission line)

e) Minimum/ignore motor contributions

f) Include fault impedance, including fault impedance between phase to phase and phase to ground in unbalanced fault

g) Consider arcing resistance

## 15.3 System configurations

### 15.3.1 Introduction

System configuration is another main factor that affects short-circuit current contributions.

### 15.3.2 Tie protective device

The status (open/closed) of tie protective devices (PD) can have significant impact on short-circuit current levels. To consider maximum short-circuit contribution, it is necessary to have all the tie PD closed. On the other hand, when calculating minimum short-circuit currents, the tie PD should be open.

### 15.3.3 Operating configuration

In addition to tie PD status, there are other system operating configuration conditions—such as parallel operating transformers, transmission lines, and cables—that also have impact on short-circuit current levels. When the parallel elements are all in operation, it normally results in higher short-circuit currents. Therefore, all these parallel elements should be considered in operation for maximum short-circuit calculation. On the other hand, for minimum short-circuit current calculation, one of the parallel branches may be considered out of service for maintenance.

### 15.3.4 Power electronic devices

Variable frequency/speed drive (VFD), uninterruptable power supply (UPS), and other types of converters can be used to control motor short-circuit current contribution. Maximum contribution from motor occurs when the power electronic device is bypassed.

## 15.4 System operating conditions

If the following devices are installed in a system, special consideration is needed in short-circuit studies.

a) Current-limiting fuses

b) Current-limiting reactors

c) Generator and transformer neutral current-limiting devices (reactor, resistor, and transformer) for grounding fault

d) Generator exciter types

# 16. Results and reports

## 16.1 Introduction

After running a short-circuit study, some essential and optional data and results should be displayed on the line view or reported in format of Crystal Report, PDF, MS Word, MS Excel, or Rich Text.

## 16.2 ANSI standard based studies

### 16.2.1 Essential data and results

Essential data and results include the following:

a) Symmetrical and asymmetrical values reported at half-cycle, 1.5 to 4 cycles, and 30 cycles

b) Asymmetrical values reported as peak or rms values

c) Thevenin equivalent impedance and *X/R* at the faulted bus

d) Three-phase, single-line-to-ground, line-to-line, and double-line-to-ground fault values

e) Phase or sequence current and voltage

f) Values for both total current and symmetrical rated circuit breakers

### 16.2.2 Optional data and results

Optional data and results include the following:

a) Asymmetrical values reported at user-selected fault time

b) Ground return current for double-line-to-ground faults

c) Positive, negative, and zero sequence Thevenin impedance at each bus

d) Calculated remote/local status for each generator

e) Interrupting study reports total and symmetrical 2-, 3-, 5-, 8-, and 30-cycle values

f) Bus voltages and branch flows throughout the system for each faulted bus

## 16.3 IEC standard based studies

### 16.3.1 Essential data and results

Essential data and results include:

a) Total initial symmetrical current $I''_{k}$
b) Total asymmetrical breaking current $I_{b}$
c) Total aperiodic component of short-circuit current $i_{dc}$
d) Total peak current $i_{p}$
e) Symmetrical breaking current $I_{b}$
f) Steady-state symmetrical current $I_{k}$
g) System branch flows to each fault location

### 16.3.2 Optional data and results

Optional data and results include:

a) Total initial symmetrical apparent power $S''_{k}$
b) Total asymmetrical breaking current $I_{b}$ at different user defined times
c) Total steady-state apparent power $S_{k}$
d) Total aperiodic component of short-circuit current $i_{dc}$ at user defined times
e) Symmetrical breaking current $I_{b}$ at user defined times

# 17. Features of analysis tools

## 17.1 Introduction

As the level of system complexity increases, the more advantageous it is to use computer-based tools to perform power system analysis. Sometimes it becomes the only way to perform system analysis. As a qualified tool to perform power system analysis, it should include some essential and/or optional features as described in this clause.

## 17.2 Essential features for ANSI-based studies

Essential features include:

a) User defined prefault voltage or based on a load flow voltage.
b) ANSI-based short-circuit study uses prefault voltage for a faulted bus and ignores prefault load flow conditions. Prefault voltage can be a fixed value for all buses or different values for individual buses. It can also be based on a system voltage profile from load studies. The values can be a

percentage of bus nominal kV or base kV. This user-defined option can often be used in system design studies where the worst short-circuit scenarios need to be simulated.

c) Calculate half-cycle, 1.5- to 4-cycle, and 30-cycle balanced and unbalanced faults (three-phase, L-G, L-L, L-L-G) for ANSI-based studies.

Half-cycle network studies for:

| **Type of device** | **Duty** |
|---|---|
| High-voltage circuit breaker | Closing and latching capability |
| Low-voltage circuit breaker | Interrupting capability |
| Fuse | Interrupting capability |
| Switchgear and MCC | Bus bracing |
| Relay | Instantaneous settings |

1.5- to 4-cycle network studies for:

| **Type of device** | **Duty** |
|---|---|
| High-voltage circuit breaker | Interrupting capability |
| Low-voltage circuit breaker | N/A |
| Fuse | N/A |
| Switchgear and MCC | N/A |
| Relay | N/A |

30-cycle network studies for:

| **Type of device** | **Duty** |
|---|---|
| High-voltage circuit breaker | N/A |
| Low-voltage circuit breaker | N/A |
| Fuse | N/A |
| Switchgear and MCC | N/A |
| Relay | Overcurrent settings |

d) Check momentary and interrupting device duty capabilities

e) Check circuit breaker closing and latching capabilities

f) Evaluate symmetrical or total rated circuit breakers

g) High-voltage circuit breaker and bus momentary duty

h) Special handling of generator circuit breakers for system and generator faults

i) For a generator circuit breaker, short-circuit current should be calculated according to the guidelines specified in IEEE Std C37.013-1997. The short-circuit duty calculated should include

symmetrical, asymmetrical, and peak kA for momentary and interrupting duty, as well as the dc kA and degree of asymmetry for interrupting duty.

j) Interrupting fault current duty as a function of circuit breaker contact parting time

k) Standard and user-definable contact parting time

l) Automatically includes no ac decay (NACD) ratio

m) User options for automatic adjustment of high-voltage circuit breaker rating

n) Modification factor for high-voltage circuit breaker, low-voltage circuit breaker, and bus momentary duty

o) Single-pole/two-pole short-circuit device duty for single-phase systems

p) Calculation should consider the following phase types: A, B, C, AB, BC, CA, LL, L1, and L2 (center-tap three-wire systems)

## 17.3 Essential features for IEC based studies

Essential features include:

a) User-definable voltage c factor

b) Three types of c factors should be considered. Below lists the c factors for maximum and minimum short-circuit current calculation. However, the c factors should be user definable.

| | **For maximum short-circuit current calculation** | **For minimum short-circuit current calculation** |
|---|---|---|
| Others < 1001 V (6% tolerance) | 1.05 | 0.95 |
| (10% tolerance) | 1.10 | 0.90 |
| High voltage, > 1 kV to 230 kV | 1.10 | 1.00 |
| High voltage, > 230 kV | 1.10 | 1.00 |

c) User-definable *R/X* adjustment methods for $I_p$ (method A, B, or C)

d) Service or ultimate short-circuit current ratings for low-voltage circuit breaker breaking capability

e) For low-voltage (< 1001 V) systems, it should be allowed for users to specify which constant value to use in the calculation of the K correction factors used to adjust the impedance of devices like transformers and generators. The selections are:

   1) 1.05 (+ 6% voltage tolerance)

   2) Use cmax = 1.05 for calculating the impedance correction factors for systems with 6% voltage tolerance

   3) 1.1 (+ 10% voltage tolerance)

   4) Use cmax = 1.1 for calculating the impedance correction factors for systems with 10% voltage tolerance

f) Consider phase-shifting transformers

g) Negative or positive impedance adjustments for maximum/minimum $I''_k$ and $I_k$

h) Automatic application of K correction factors (i.e., $K_T$, $K_G$, $K_{SO}$)

i) Automatically determines meshed and non-meshed networks for calculating $I_b$, $I_k$, and $I_{dc}$

j) $I_b$ for meshed network adjusted by individual machine contributions

k) Consider both near and far short-circuit current from generators

l) Short-circuit study calculations based on IEC 60909, IEC 60282, IEC 60781, and IEC 60947

m) Transient short-circuit calculations using IEC 61363

n) Compare protective device ratings with calculated short-circuit values

## 17.4 Essential features for all standards

Essential features include:

a) Consider transformer tap adjustment; for more accurate calculation results, transformer tap adjustment should be considered

b) Protective device duty comparison based on total bus fault current or maximum through fault current

c) Element parameter adjustments for impedance values, cable/line length, and temperature adjustment of resistance, both individually and globally

d) Load terminal short-circuit calculations

e) Study results analyzer
Short-circuit calculations for a practical system can involve tens of cases representing different operating conditions. Individually reviewing reports for these cases will take a great amount of time for engineers. A computer software tool for short-circuit study should provide a tool that can be used to review detailed results of short-circuit calculation for one study, as we list results for all short-circuit study cases together for comparison. Furthermore, it should be able to automatically identify the worst case from all the studies carried out and present it to the user.

   Figure 91 and Figure 92 show a sample from a short-circuit results analyzer. Figure 91 presents results of circuit breaker device duty evaluation from four different studies. These studies represent different system operating conditions. The study results analyzer should be able to automatically extract results from these study reports and present it in a summary format. It should also identify any underrated devices based on user-specified thresholds.

   Figure 92 shows the worst case of device duty for a panel system. It performs duty comparison for the panel's main circuit breakers as well as ones for each individual circuits. The worst case scenario is automatically determined among the selected studies once the worst case option is checked. For each device, it shows the results from the worst case (identified by the report name) along with the operating conditions used in the studies, such as system configurations and engineering data revisions.

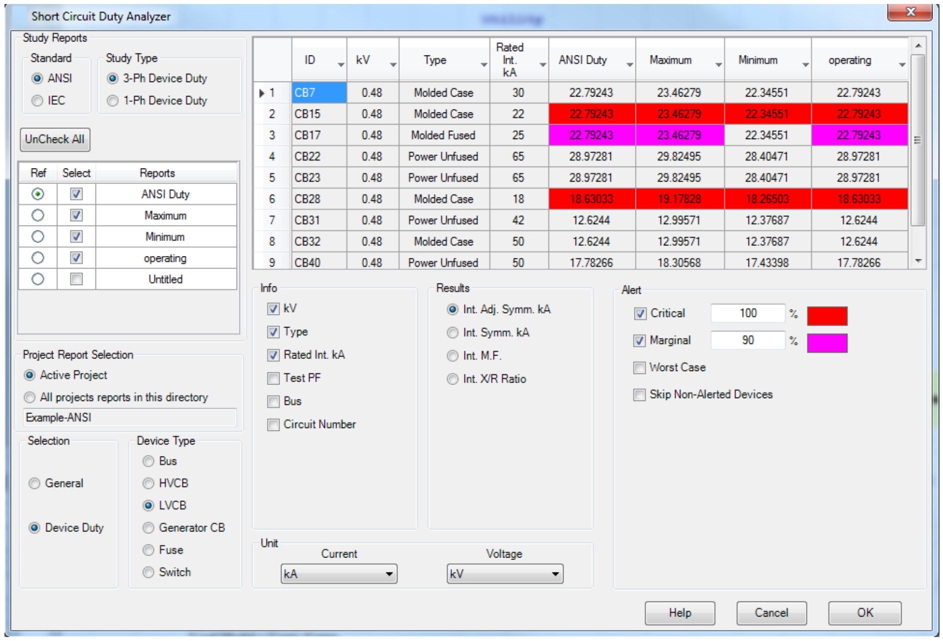



**Figure 91—Result analyzer for comparing multiple studies**

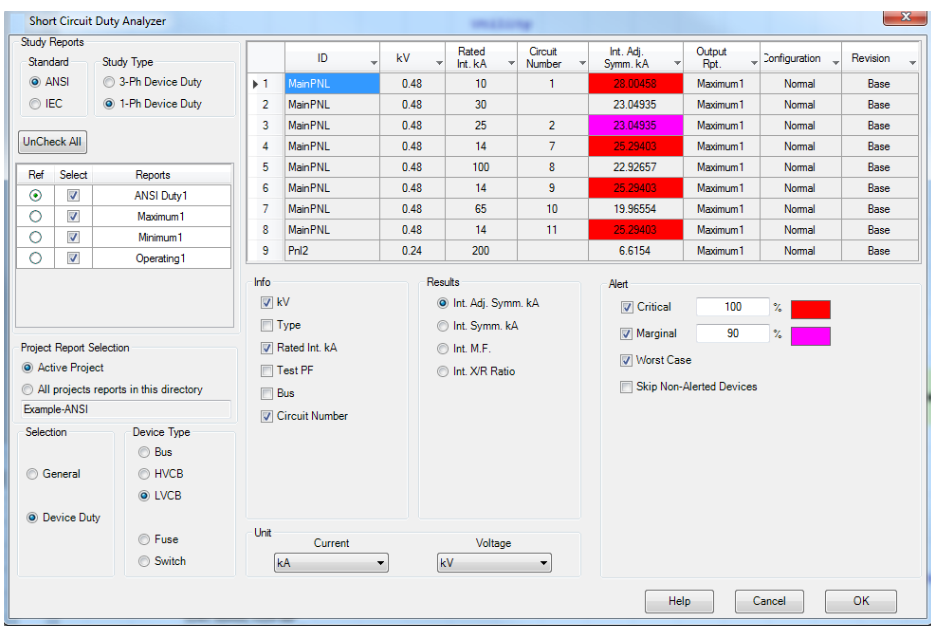



**Figure 92—Result analyzer identifying worst case**

## 17.5 Optional features

Optional features include:

a) Consider prefault load flows.
Actual prefault load flow operating conditions can be included in short-circuit calculation. The methods described in ANSI and IEC standard current ignores the effect of prefault load flows,

although in IEC's method prefault operating conditions are considered to a certain degree in parameter adjustments for generators and transformers.

b) Custom reports using data blocks.
Necessary calculation results must be provided. For different usage purpose and different organization requirement, customizable reports can be provided by using data blocks.

c) Detailed and summary reporting options.
Detailed short-circuit study results are needed. A summarized report gives a simplified reference such as for total fault current at each bus.

d) Generates relay test set compatible plots for transient short-circuits.
In a simple click, automatically perform a set of predefined short-circuit study scenarios representing various system operating conditions and present the calculation results to the user with worst conditions identified. This set of core short-circuit study scenarios includes all essential cases that are required to evaluate whenever there is a system operation failure or addition.

e) Integrate with protective device coordination.
Three-phase modeling for unbalanced systems such as distribution systems. The modeling technique should account for unbalanced system parameters as well as unbalanced prefault operating conditions.

f) Short-circuit calculation for simultaneous faults in the system.

# 18. Illustration examples

## 18.1 ANSI example system

### 18.1.1 System and data

Considering the general example in IEEE Std 3002.2, in normal configuration there should be no concern (alert) based on the input data. With system configuration changes, such as a closed tie circuit breaker, device duty needs to be checked.

### 18.1.2 Study scenarios

Taking the general example in IEEE Std 3002.2, in normal configuration tie circuit breaker CB:6 is open. For a three-phase fault at Bus A the symmetric interrupting short-circuit current is 28.15 kA, and fault at Bus B is 30.4 kA. All the circuit breakers and the buses do not have duty problems, (no critical alert). The short-circuit contribution results are as shown in Figure 93.

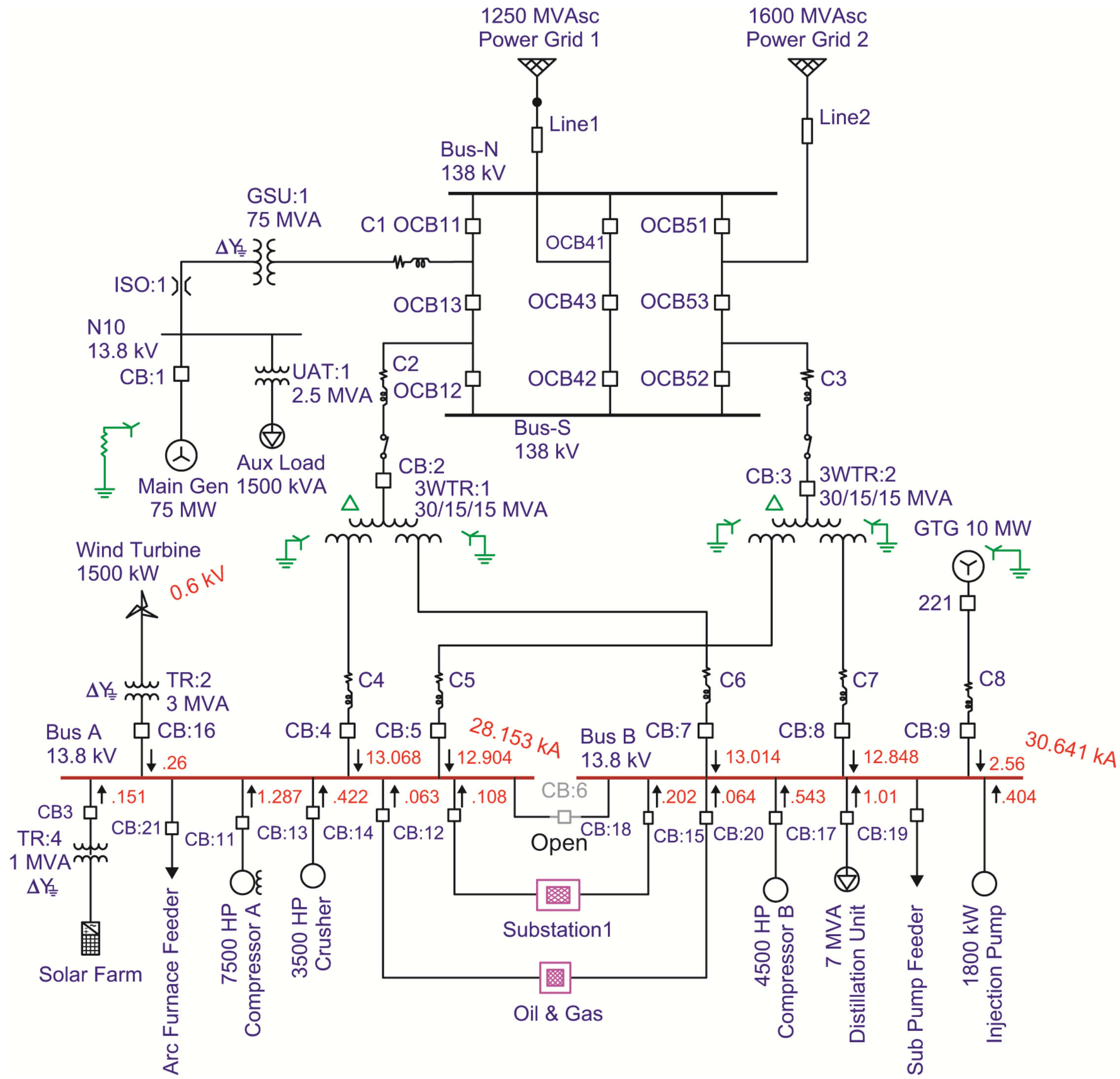



**Figure 93—Short-circuit example system in normal configuration (IEEE 3002 system)**

Consider another case that the tie circuit breakers CB:6, CB19-2, and CB13 are closed. For a three-phase fault at Bus A the symmetric interrupting short-circuit current is 48.75 kA, and at Bus B it is also 48.75 kA. There is no critical alert. The short-circuit contribution results are as shown in Figure 94.

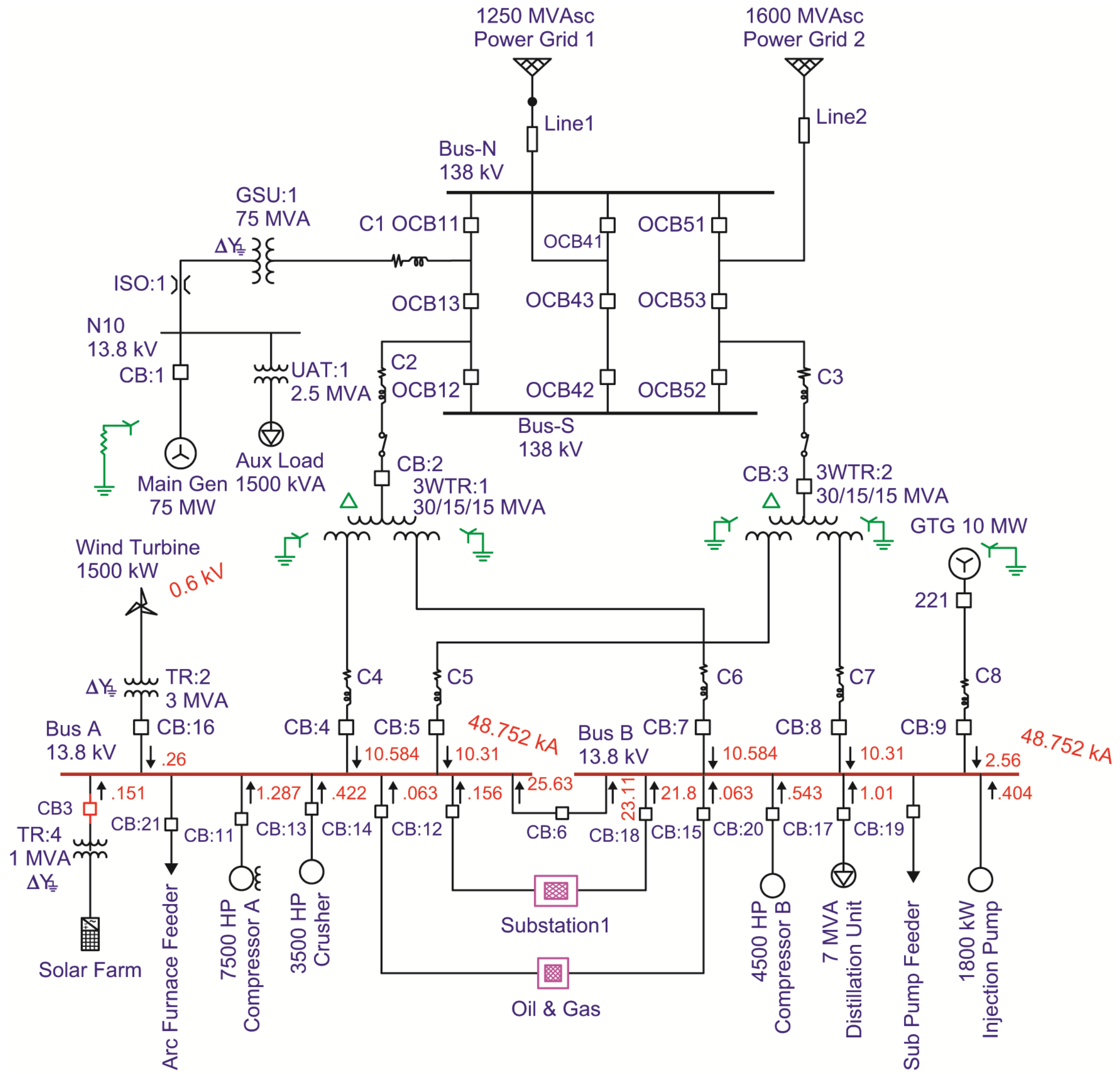



**Figure 94—Short-circuit example system with CB:6, CB:19-2, and CB13 closed**

Unbalanced fault studies may be conducted for purposes such as protective device coordination. Taking the general example in this standard again, a summary report for faults at Bus A and Bus B is shown in Figure 95.

**Short-Circuit Summary Report**

1/2 Cycle - 3-Phase, LG, LL, & LLG Fault Currents

Prefault Voltage = 100 % of the Bus Nominal Voltage

| Bus | | 3-Phase Fault | | | Line-to-Ground Fault | | | Line-to-Line Fault | | | *Line-to-Line-to-Ground | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ID | kV | Real | Imag. | Mag. | Real | Imag. | Mag. | Real | Imag. | Mag. | Real | Imag. | Mag. |
| Bus A | 13.800 | 3.729 | -50.938 | 51.075 | 6.816 | -54.725 | 55.148 | 44.353 | 3.349 | 44.480 | -49.484 | 25.757 | 55.786 |
| Bus B | 13.800 | 3.729 | -50.938 | 51.075 | 6.816 | -54.725 | 55.148 | 44.353 | 3.349 | 44.480 | -49.484 | 25.757 | 55.786 |

All fault currents are symmetrical (1/2 Cycle network) values in rms kA.
* LLG fault current is the larger of the two faulted line currents.

**Figure 95—Short-circuit summary report for faults at Bus A and Bus B**

## 18.2 IEC Example system

### 18.2.1 System and data

Considering the example in 10.8 as shown in Figure 96, in normal configuration there should be no concern (alert) based on the input data. With system configuration changes, such as a closed tie circuit breaker, device capability (duty) need to be checked.

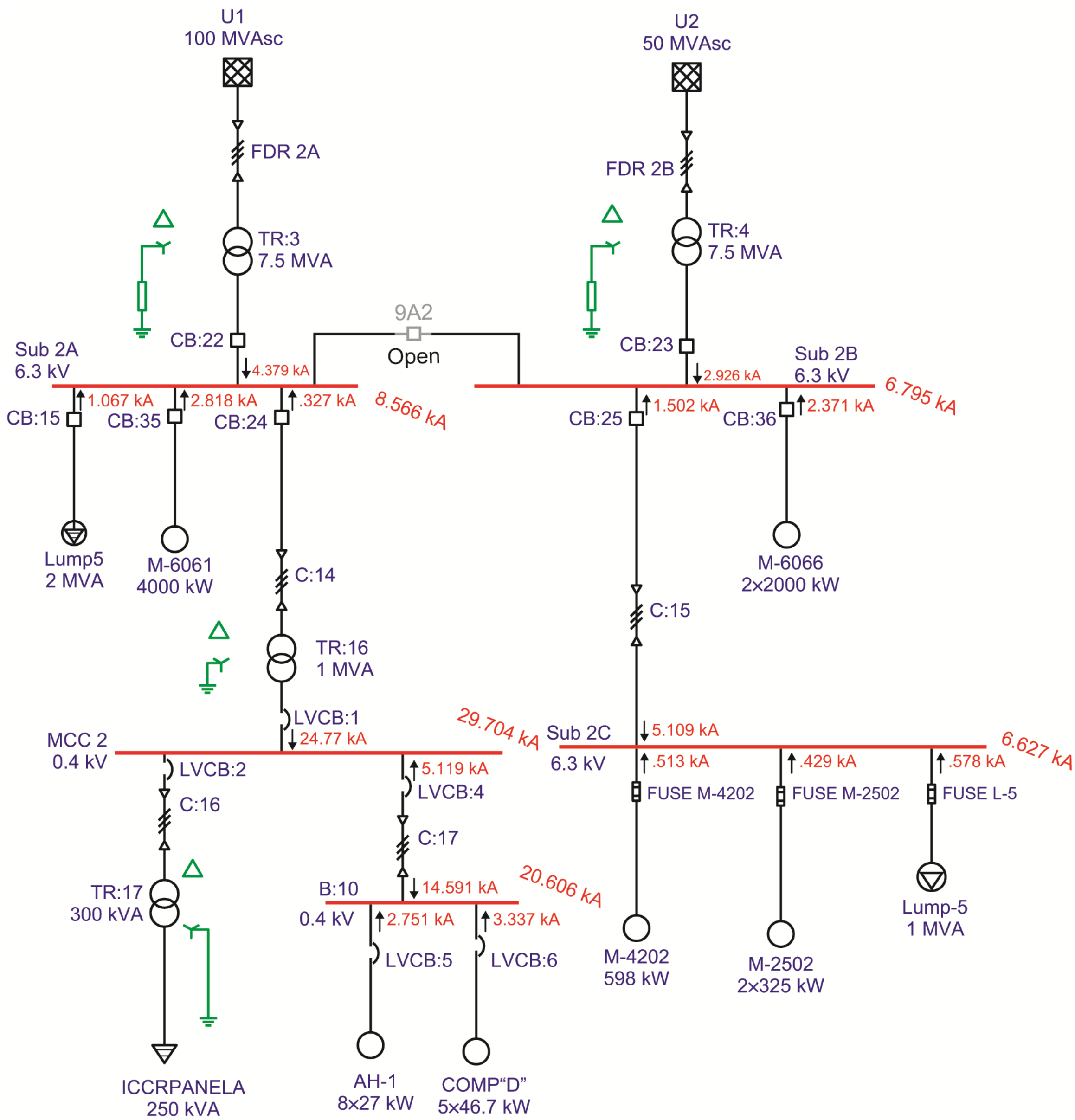



**Figure 96—Simplified IEC sample system in normal configuration**

### 18.2.2 Study scenarios

As shown in Figure 96, Substation Sub 2A is designed based on IEC standards. In normal configuration tie circuit breaker 9A2 is open. For a three-phase fault at Sub 2A and Sub 2B the short-circuit current is 8.566 kA and 6.795 kA, respectively. All the circuit breakers and the buses do not have duty problems (no critical alert). The short-circuit contribution results are as shown in Figure 96.

Considering another case that the tie circuit breaker 9A2 is closed. For a three-phase fault at Bus 2A and Bus 2B the short-circuit current is now 15.361 kA as shown in Figure 97. The capabilities of all the devices under this configuration need to be checked. Any concern (alert) should be corrected.

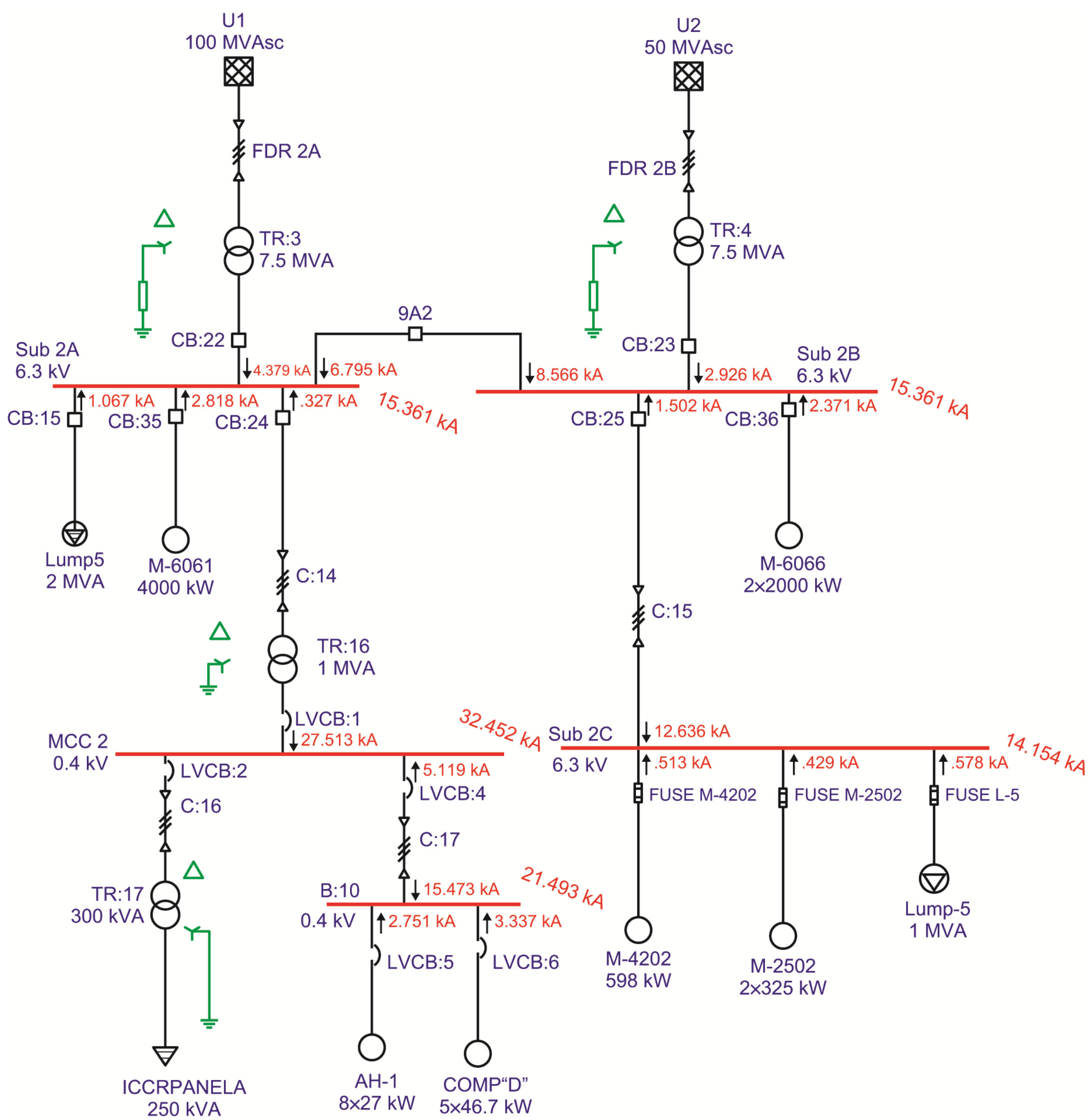



**Figure 97—Simplified IEC sample system with circuit breaker 9A2 closed**

# Annex A

(informative)

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